Arnold Schwarzenegger
Governor

ASSESSMENT OF CALIFORNIA CHP MARKET AND POLICY OPTIONS FOR INCREASED PENETRATION

DRAFT CONSULTANT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Electric Power Research Institute

APRIL 2005
CEC-500-2005-060-D

Prepared By:
Electric Power Research Institute
Ellen Petrill
Dan Rastler
Palo Alto, California
Contract No. 500-01-025

Prepared For:
California Energy Commission
Public Interest Energy Research (PIER) Program

Nancy Libonati
Contract Manager

Mark Rawson
Project Manager

Laurie ten Hope
Program Area Team Lead

Ron Kukulka
Acting Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Scott W. Matthews
Acting Executive Director

Assessment of California CHP Market and Policy Options for Increased Penetration

Draft Report, April 2005

Cosponsors
Public Interest Energy Research Program (PIER)
California Energy Commission
1516 Ninth Street
Sacramento, California 95814

PIER Project Manager
M. Rawson

EPRI
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Manager
E. Petrill
D. Rastler

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Energy and Environmental Analysis, Inc.

EPRI Solutions, Inc.

Energy and Environmental Economics, Inc.

Electric Power Research Institute

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CITATIONS

This report was prepared by

Energy and Environmental Analysis, Inc.
1655 North Fort Myer Drive, #600
Arlington, VA 22209

Principal Investigator
K. Darrow

EPRI Solutions, Inc.
942 Corridor Park Blvd.
Knoxville, TN 37932

Principal Investigator
S. McNulty

Energy and Environmental Economics, Inc.
353 Sacramento Street, Suite 1700
San Francisco, CA 94111

Principal Investigator
S. Price

This report was prepared for

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

and

Public Interest Energy Research Program (PIER)
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

This report describes research jointly sponsored by EPRI and the California Energy Commission.

The report should be cited in the literature in the following manner:

Assessment of California CHP Market and Policy Options for Increased Penetration, EPRI, Palo Alto, CA, California Energy Commission, Sacramento, CA: 2005.

ABSTRACT

The California Energy Commission (Energy Commission) identified a need to reassess the market opportunities for combined heat and power (CHP) applications and the role they could play in contributing to the State's Energy Action Plan. The use of CHP systems in commercial, industrial, and multifamily residential establishments could improve the overall efficiency of energy use by displacing fuel use for boilers while at the same time displacing marginal, predominantly gas-fired, sources of electricity generation. Since CHP could have a potentially large role in supporting California's loading order, this research project was undertaken. This report provides information to help California stakeholders understand:

- The technical and economic potential for CHP in California
- End-user drivers and adoption barriers to CHP
- Cost and benefits of incentives and policy options necessary to realize the CHP opportunity
- Technology gaps and R&D needs to move the CHP market opportunity forward.

EXECUTIVE SUMMARY

Introduction

Despite higher natural gas prices, the market potential for combined heating and power (CHP) in California is substantial and could contribute significantly to the State's overall Energy Action Plan loading order. The projection for the base case (today's scenario) market penetration for CHP is near 2,000 MW. Under a high deployment scenario, the market penetration of CHP is over 7,300 MW. This scenario includes existing incentives, facilitation of the power export market, addition of a T&D support payment, a CO2 reduction payment, the rapid development and deployment of advanced technology, and an overall improvement in customer acceptance of CHP investment opportunities. This report describes the CHP market penetration analysis conducted for this project, including market feedback from California customers, and the impacts of a range of policy options on CHP market penetration. The report concludes with a summary of findings and recommendations for next steps toward achieving CHP market penetration with high societal benefits because both customer and utility benefits are provided

Background

The California Energy Commission identified a need to reassess the market opportunities for combined heat and power (CHP) applications and the role they could play in contributing to the State's Energy Action Plan. The Energy Commission evaluated the CHP market potential in 1999.[1] This study identified the CHP market opportunity to be over 12,000 MW of technical potential and an estimated 4000 MW of economic market potential over the 2002-2020 period. This earlier assessment provided useful baseline for input to the State's Integrated Energy Policy Report.

In the last five years, however, there have been several significant changes in the California energy economy and an evolution of need for policy direction and incentives to encourage future CHP markets. These changes include:

- The outlook for natural gas and electricity supply and price to end-users has changed significantly.
- Estimates for cost and performance of CHP technology, both emerging and established, are changing due to continued development and demonstration.

The use of CHP systems in commercial, industrial, and multifamily residential establishments could improve the overall efficiency of energy use by displacing fuel use for boilers while at the

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[1] *Market Assessment of Combined Heat and Power in the State of California*, prepared by Onsite Sycom Energy Corporation, California Energy Commission Report P700-00-009, July 1999 (released October 2000.)

same time displacing marginal, predominantly gas-fired, sources of electricity generation. Since CHP could have a potentially large role in California's loading order as directed by the Energy Action Plan, this research project was undertaken to provide input to the Integrated Energy Policy Report (IEPR) for 2005 in the following areas:

- Quantify and update the technical and economic potential for CHP in California
- Assess the end-user adoption barriers to CHP
- Develop approaches for incentives and other options to realize the CHP opportunity
- Assess the technology gaps and R&D needs to move the CHP market opportunity forward.

Objectives and Approach

The objectives of this research project are to provide the following information in support of energy policy planning for the State of California:

- Develop estimates of the current CHP capacity in the state and the impact of the current SGIP program on CHP market penetration.
- Develop new estimates of technical and economic market potential for CHP and CCHP based on evaluation of current California business activity and using new forecasts for natural gas and retail electric rates.
- Provide analysis of the costs and benefits of various incentive options to promote development of the CHP market opportunity.

To perform the analysis, the California Energy Commission collaborated with EPRI and its project team of Energy and Environmental Analysis, Inc. (EEA), EPRI Solutions, Inc. and Energy and Environmental Economics, Inc. (E3). EEA conducted the market penetration analyses, EPRI Solutions assessed user adoption barriers, E3 developed alternative policy recommendations and quantified their costs and benefits; and EPRI provided an assessment of R&D gaps to improve CHP market penetration and performed overall project management.

Results and Key Findings

California CHP Market Assessment

- There are already 9,130 MW of active CHP installed in California at 776 sites. Nearly 90% of this capacity resides in large systems with site capacities of over 20 MW.
- The remaining technical market potential was estimated based on an evaluation of existing inventory of facilities in California and including an estimate of future growth during the forecast period (2005-2020). Three markets were considered:
- traditional CHP in which the electricity is used on site and the heat is used to offset facility steam or hot water loads,
    - the combined cooling heating and power (CCHP) market in which at least part of the thermal energy is used to provide air conditioning using absorption chillers;

    - the large export CHP market in which large industrial facilities provide a steam host for CHP systems that feed power to the electric grid.

- Considering all markets both existing and new facilities, there is a total remaining technical market potential that approaches 30,000 MW (Figure ES-1). The remaining technical market potential for the traditional CHP market was estimated to be 14,381 MW in existing facilities and 5,793 MW from expected new facilities during the period 2005-2020. There is a net technical market potential for CCHP projects of 4,123 MW, and an export market potential of 5,935 MW.

- Reciprocating engine systems, the dominant technology in markets less than 5 MW, are unable to meet the accelerated 2007 emissions requirements in the Southern California until 2010. In addition, small gas turbines will require very expensive after-treatment emission control systems until that technology improves. Consequently, there is no market penetration in Southern California during the first 5 years for systems less than 20 MW.

- A base case for CHP market penetration was developed based on expected future gas and electric prices, existing incentive programs (Small Generation Incentive Program and incentive gas rates for CHP), existing and proposed emissions requirements, and existing CHP technology cost and performance with evolutionary improvements over time. The cumulative 2005-2020 market penetration of CHP under base economic and market assumptions was estimated to be 1,966 MWs (Table ES-1).

- Several alternative forecast scenarios were considered, ranging from removal of the existing CHP incentive programs to scenarios with additional CHP incentives added to the current mix. Table ES-2 summarizes the scenarios and the forecast results. The cumulative market penetration for these scenarios range from a low of 1,141 MW for the no incentives case to a high of 7,340 MW for a high deployment case that includes existing incentives, facilitation of the power export market, addition of a T&D support payment a CO2 reduction payment, the rapid development and deployment of advanced technology, and an overall improvement in customer acceptance of CHP investment opportunities. The electricity capacities shown in the tables reflect the installed capacity of the CHP systems. In addition to this capacity, in the cooling CHP markets the systems avoid summer peak electric capacity due to the replacement of electric air conditioning with thermally activated systems. This additional electricity capacity resource is equal to 70-90 MW in the base case and 130-170 MW in the high deployment case.

- The base case provides total benefits over the 15 year forecast period of 400 trillion Btu of energy savings, close to $1 billion in reduced facility operating costs, and a CO_2 emissions reduction of 23 million tons.

- The high deployment case greatly increases the cumulative benefit measures compared to the base case, energy savings increase to 1,900 trillion Btu, customer net reduction in energy costs increases to $6 billion, and CO_2 emissions reduction increases to 112 million tons.

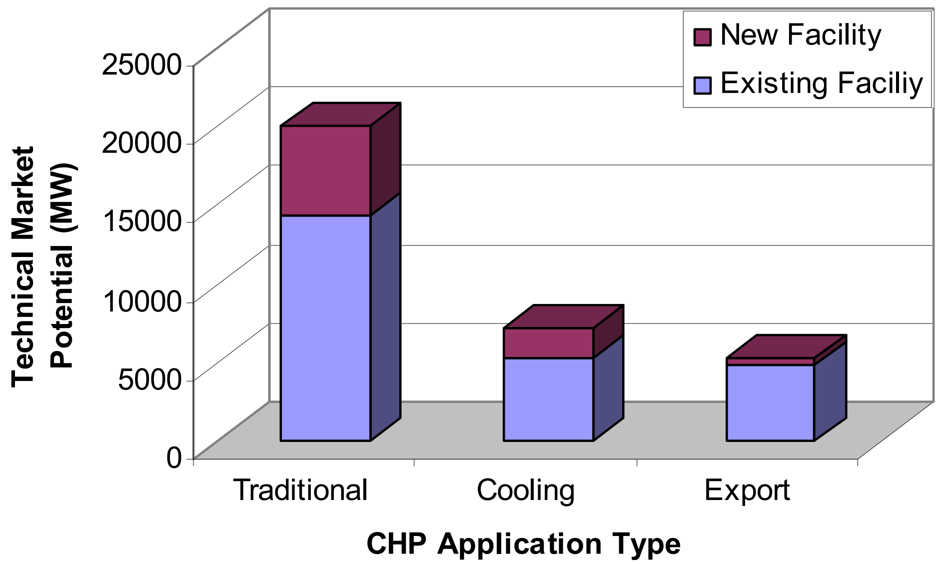


Figure ES 1
CHP Technical Market Potential

Table ES 1
Base Case Cumulative Market Penetration (2005-2020) by Size and Utility

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	167	239	286	72	74	839
	SMUD	8	14	18	5	0	45
	Other North	2	3	3	0	0	8
North Total		178	256	306	77	74	891
South	LADWP	7	5	14	5	15	47
	SCE	155	181	318	60	133	847
	SDG&E	28	39	63	6	18	155
	Other South	6	6	11	4	0	27
South Total		196	231	406	76	167	1,075
Grand Total		373	487	713	153	241	1,966

Table ES 2
Alternative Forecast Scenario Results

Scenario	Onsite CHP MW	Export CHP MW	Total Market Penetration MW	Description
Base Case	1,966	0	1,966	Expected future conditions with existing incentives
No Incentives	1,141	0	1,141	Remove SGIP, CHP incentive gas price, and CHP CRS exemptions)
Moderate Market Access	1,966	2,410	4,376	Facilitate wholesale generation export
Aggressive Market Access	2,479	2,869	5,348	$40/kW year T&D capacity payments for projects under 20 MW, global warming incentive, and wholesale export
Increased (Alternative) Incentives	2,942	0	2,942	Extended SGIP (incentives on first 5 MW for projects less than 20 MW, $0.01/kWh CHP production tax credit
Streamlining	2,489	0	2,489	Customer behavior changes: higher response to payback levels and greater share of market that will consider CHP
High R&D on Base Case	2,764	0	2,764	Rate of technology improvement accelerated 5 years
High Deployment Case	4,471	2,869	7,340	Accelerated technology improvement with aggressive market access and streamlining to improve customer attitudes and response

Market Research Findings

California energy users, like those throughout the country, adopt CHP for two basic reasons. The first, and most important, is to reduce their overall cost of energy. The second is the increased power reliability that many energy users feel a CHP application will provide them. Although there are many factors that affect project economics, most energy users ultimately reduce the complexity of a CHP decision to a simple payback calculation. Yet, the payback threshold that California energy users apply is very demanding – less than half of all energy users would be willing to accept a payback of even two years for a CHP project (Figure ES-2). Most would require a payback of one year or less.

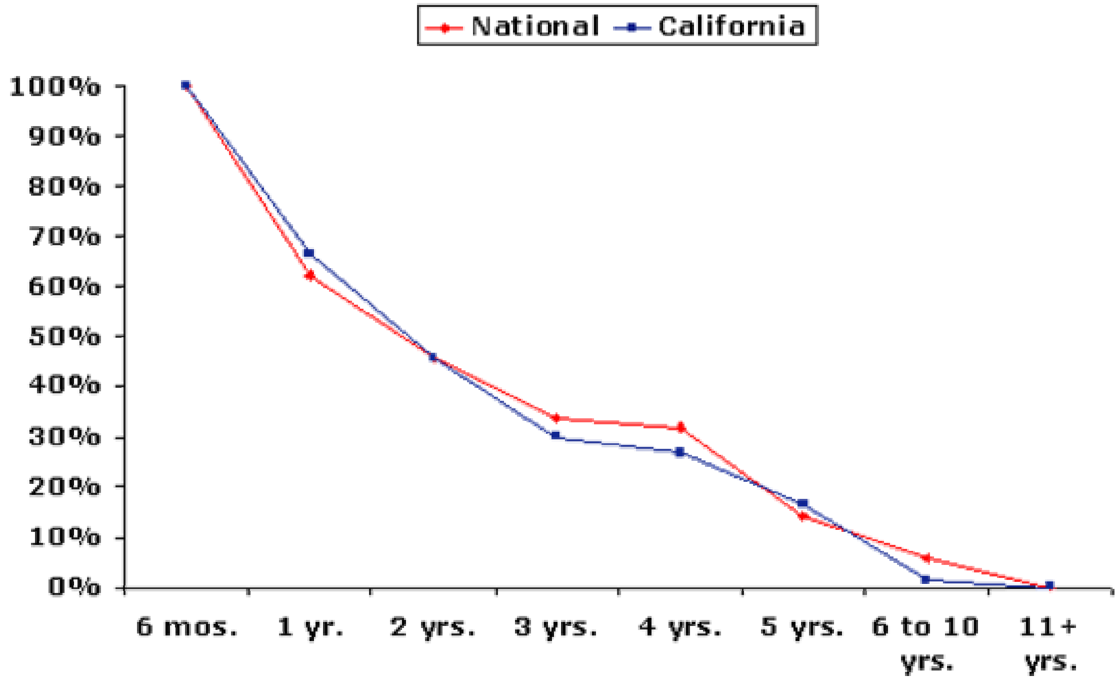
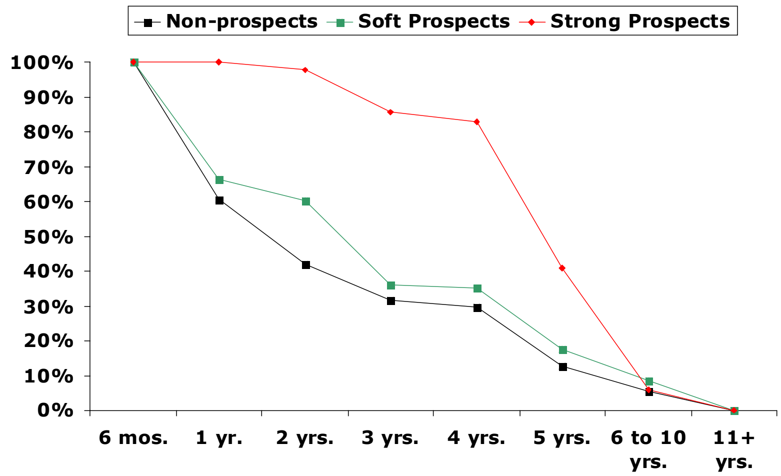


Figure ES 2
Payback Acceptance in California and Nationwide

The strongest prospects for CHP applications – those energy users who are already actively investigating CHP options – are somewhat more tolerant of longer paybacks[2]. But even within this group of strong prospects, the majority require a payback of less than five years in order to pursue an onsite generation project (Figure ES-3).

[2] The Primen/ESI study considers prospects as energy users that say they are more than 50% likely to acquire baseload distributed energy (DE) within the next two years. Primen then breaks down the prospects into strong prospects and soft prospects. Strong prospects are those that say they are likely to acquire DE within the next two years and they are actively evaluating their options. Soft prospects on the other hand also say that they are more than 50% likely to acquire DE within the next two years, but have not begun to actively investigate their options.



Source: *Primen's 2003 Distributed Energy Market Survey*

Figure ES 3
Payback Acceptance by Prospect Type

These stringent payback requirements imply that projects that often would be considered economic by vendors in the energy industry will not be adopted by California energy users. Users simply require higher rates of return than typically believe necessary.

The research also found the most commonly cited non-economic barrier to CHP adoption is the fact that senior management does not view energy issues (including energy costs) as a particularly high priority. This translates into an unwillingness to devote capital and management time to a CHP project when those resources could be devoted to other activities. Several energy users interviewed noted that the electricity price spikes and rolling blackouts at the beginning of the decade caused their management to place a higher priority on energy – at least for a time. In fact, this focus resulted in a number of recent CHP projects being completed in California, and for several others that were begun but not completed.

However, subsequent increases in natural gas prices, combined with the apparent end of the electricity "crisis," have dampened the enthusiasm of many energy users. Given the emphasis on project economics and requisite rapid payback among energy users, it is not surprising that the policy initiatives energy users most strongly favored were ones designed to improve CHP project economics.

Policy Options to Encourage Market Penetration of CHP

To understand the implications of potential policy instruments the Integrated Energy Policy Report (IEPR) could recommend to encourage CHP market growth, an analysis of several policy portfolios was conducted that could be implemented by the State. This research contributes to development of approaches for incentives and other options to realize the CHP opportunity estimated in the market analysis assessment (Chapter 2) and the market research work described in (Chapter 3) and will provide insights for the analysis and subsequent recommendations of future research needs (Chapter 5).

The results summarized in Figure ES-4 show each policy portfolio that was evaluated, net benefits of each stakeholder including CHP / CCHP owners and users, electric utilities and their customers, and society, and the cumulative market penetration expected for that policy through 2020.

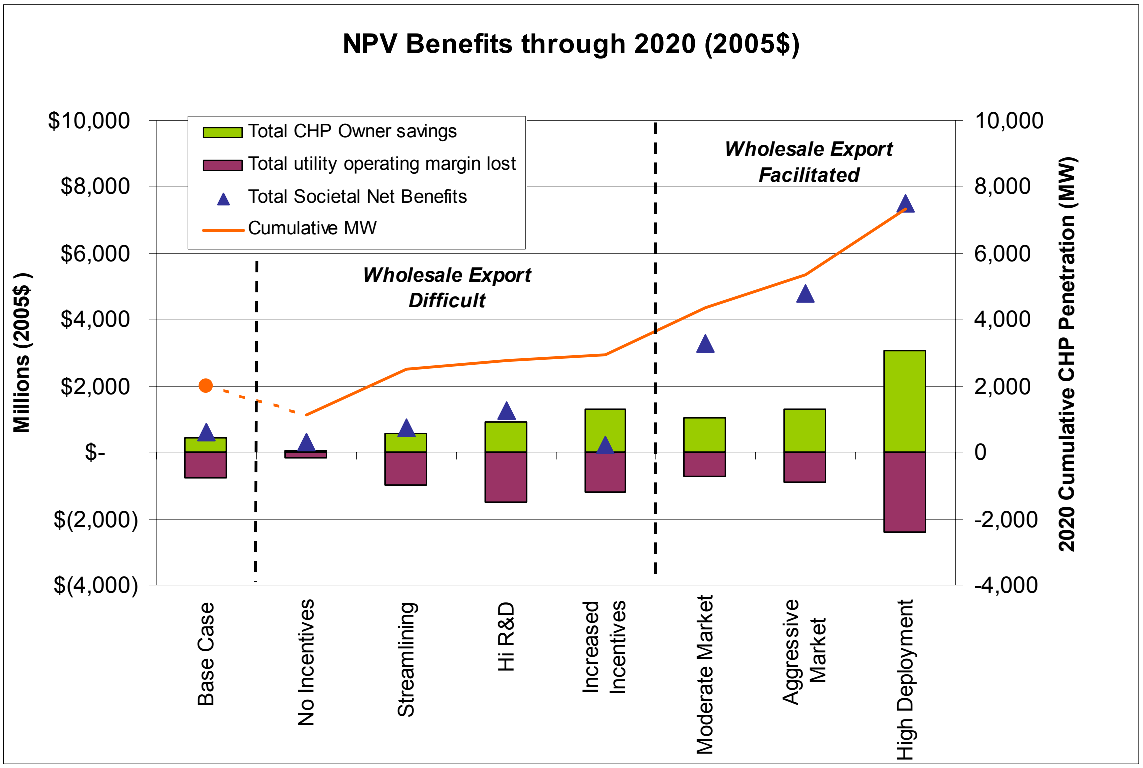


Figure ES 4
Net Benefit Results by Stakeholder of Policy Scenarios ($2005) and CHP Penetration Levels (MW) in 2020

A summary of findings from the policy portfolio analysis show:

- A primary distinguishing difference between scenarios is a policy that facilitates the export of energy from CHP onto the transmission and distribution system at wholesale electricity prices.
- The three scenarios to the right of the dashed line allow for wholesale energy export and yield the highest penetration because the installations that benefit from export tend to be very large as described in Chapter 2.

- The wholesale export cases also result in the highest societal benefits because they result in significant energy production at higher efficiency than central station plants.
- All policy options, including the base case, result in losses in electric utility revenue that are greater than the corresponding savings to the utility. This loss would need to be made up with either rate increases or by the ability to extract increased utility value from CHP installations, or both.
- Market access portfolios that have policies to encourage participation in energy and capacity markets, as well as T&D capacity, do tend to mitigate the utility losses.
- Increasing incentives to encourage more CHP adoption alone decreases the societal benefits from CHP installations and exacerbates the losses to the utility and non-participating customers.

Conclusions

- Despite higher natural gas prices, the market potential for CHP remains substantial and could contribute significantly to the State's overall Energy Action Plan loading order. The base case market penetration for CHP is near 2,000 MW by 2020 which is about half that of a 1999 forecast that was based on gas prices that were much lower than the current forecast. The high level of gas prices makes competition more difficult for CHP with correspondingly longer paybacks and lower acceptance levels among potential adopters. Reciprocating engine systems, the dominant technology in markets less than 5 MW, are unable to meet the accelerated 2007 emissions requirements in the Southern California until 2010. In addition, small gas turbines will require very expensive after-treatment emission control systems until that technology improves. Consequently, there is no market penetration in the Southern California during the first 5 years for systems less than 20 MW.
- Market penetration of emerging technologies such as fuel cells and microturbines remains very low throughout the forecast period due to uncompetitive early market pricing that is not offset by the SGIP payments.
- The difficulty in selling excess electricity from a CHP generator leaves the 5,200 MW export market potential untapped. The market requires scheduling hour-by-hour exports with the CAISO, and finding an electricity buyer. A policy that encourages electric utilities to purchase electricity from CHP as delivered at the prevailing wholesale price could address this problem and encourage larger CHP installations in facilities that use significant amounts of thermal energy. This could look like 'net metering' at the wholesale energy price.
- A critical factor for CHP market penetration is the ability of these systems to be both cost competitive and to have acceptable emission levels. The high technical market potential suggests there is need for continued R&D towards technologies and systems that would be most suitable for key market segments.
- Energy cost savings and reliability/security are the key drivers for California end-users to adopt CHP, however, short payback times < 3 years will limit market adoption.
- Policy options that energy users said would most likely increase the odds of a CHP project going forward were: modifying the SGIP so that larger projects could participate; and allowing CHP owners to sell excess power to the grid.

- Policy options that encourage CHP operation at times of high system and local T&D value reduce utility operating margin losses and result in higher societal benefits. For example, the utility would pay CHP owners for an operating agreement to ensure that the unit will be running during critical peak days, during a local T&D capacity constraint, and/or at times of high electricity market prices. Alternatively, utility would pay CHP owners for a demand limitation agreement where the customer agrees to limit demand to a predetermined level during the critical periods, thereby relying on the CHP system to meet the customer's energy needs during these periods.

Recommendations

From the policy perspective, the team's main recommendation is to shift towards policies that provide payments for utility-side services and decrease incentive payments with no operational requirements. This approach coordinates operation of CHP / CCHP to capture both customer-side and utility-side benefits simultaneously. This approach follows the recommendations of the California Energy Commission-sponsored DER Public/Private Partnership to focus on win-win opportunities, where multiple stakeholders benefits and no stakeholders are harmed.

A move towards payment for service, rather than incentive, over time will result in:

- Increased penetration of CHP / CCHP which typically have higher efficiency than central station generation,
- Decreased losses to the electric utility and non-participating customers relative to the SGIP incentive approach,
- A clearer exit strategy that ultimately eliminates all incentive 'subsidies' and has only payments based on services that CHP / CCHP provides,
- Higher societal benefits because both customer and utility benefits are provided,
- Less resistance from stakeholders than increasing subsidies because payments are matched with benefits, and rate impacts are therefore lower.

Our analysis considered a number of policies of this type that pay for generation capacity, energy (including losses), T&D capacity, and CO_2 mitigation benefits of CHP. We focused on these policies because they provide the largest benefits for most CHP/CCHP installations; however, this list is not comprehensive. The CPUC DG Costs and Benefits proceeding is also defining services that DG could potentially provide. An informal stakeholder collaborative process should be used to develop and assess innovative policy options that provide benefits to all stakeholders.

The specific policies of this type that we consider in our analysis, and we recommend further investigation into, include:

- Facilitating electricity export to the grid, particularly for large CHP installations, through an approach similar to 'net metering' for renewables but at the wholesale electricity price.
- Payment for T&D capacity through a demand limitation agreement for CHP / CCHP with physical assurance in capacity constrained areas.

- Payment for availability during system peak times based on generation capacity value to improve resource adequacy.
- Payment based on CO_2 emission reductions CHP achieves through higher efficiency (through a production tax credit in $/kWh or other mechanism)

For our analysis it was assumed that policies could be structured that would make payments based on the actual value of these services. An informal stakeholder collaboration process should assess and further develop workable policies to present to the CPUC. The next step by the State would be to consider the recommended policies and develop appropriate mechanisms such as contract and operating agreement details, basis of payments, metering, solicitation, and other factors mechanisms in formal CPUC proceedings.

From an R&D perspective, near-term R&D actions by the Energy Commission should address the following areas:

- Ensure the availability of low emission gas turbines and internal combustion engines for CHP markets
- Demonstrate that low emission control solutions for these technologies are viable and economic over time through field tests and demonstrations
- Develop and demonstrate standardized CHP systems for key California market segments

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1
INTRODUCTION

This chapter provides an introduction to this research report including relevant background, the objectives, approach, the project team and how the results are reported and organized in other chapters of this document.

Background

The California Energy Commission has identified a need to incorporate energy efficiency, demand response, renewables, and distributed generation into a *preferred energy loading order*.[3]

Distributed generation offers the option of using fuel efficiently, while reducing load on the electric supply system and avoiding the challenges of central station and transmission siting processes and timing. Additional work is needed to consider distributed generation in demand and supply forecasting, the impacts of distributed generation on the transmission and distribution systems as its level of adoption increases, and other issues.[4]

Combined heat and power (CHP) is the most energy efficient and cost-effective form of distributed generation. The use of CHP systems in commercial, industrial, and multifamily residential establishments will improve the overall efficiency of energy use by displacing fuel use for boilers while at the same time displacing marginal, predominantly gas-fired, sources of electricity generation. Since CHP could have a potentially large role per California's Joint Energy Action Plan, the Commission initiated this research project to:

- Quantify and update the technical and economic potential for CHP in California
- Assess the end-user adoption barriers to CHP
- Develop approaches for incentives and other options to realize the CHP opportunity
- Assess the technology gaps and R&D needs to move the CHP market opportunity forward.

The Energy Commission had evaluated the CHP market potential for California in 1999.[5] This study provided a useful baseline of the potential contribution of CHP to the California energy mix over a 20-year period. In the last five years, however, there have been significant changes in

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[3] *State of California's Energy Action Plan,* California Power Authority, California Energy Commission, and California Public Utilities Commission, May 8, 2003.
[4] *Staff Proposal for Scoping the 2005 Integrated Energy Policy Report*, Docket No. 03-IEP-01, California Energy Commission, August 4, 2004.
[5] *Market Assessment of Combined Heat and Power in the State of California*, prepared by Onsite Sycom Energy Corporation, California Energy Commission Report P700-00-009, July 1999 (released October 2000.)

the California energy economy and an evolution of need for policy direction and incentives to encourage future CHP markets. These changes include:

- The outlook for natural gas and electricity supply and price to end-users has changed significantly.
- The estimates for cost and performance of CHP technology, both emerging and established, are changing due to continued development and demonstration of advanced technologies both through the technical programs within the Energy Commission such as Environmentally Preferred Advanced Generation and the US Department of Energy's Energy Efficiency and Renewable Energy Program, and the recent demonstration experience of the Self Generation Incentive Program (SGIP).
- Insights from the SGIP may also provide a more accurate basis for predicting future market response to CHP as a function of economic payback and incentive levels.

Objectives:

The objectives of this research project are to provide the following information in support of energy policy planning for the State of California:

- Estimate the current CHP capacity in the state
- Assess the impact of the SGIP on CHP market penetration
- Document the current and advanced cost and performance of CHP technologies and thermally activated technologies such as absorption cooling.
- Evaluate CHP with traditional heat recovery and combined cooling heating and power (CCHP.)
- Estimate of technical market potential for CHP and CCHP based on evaluation of California business activity
- Estimate of economic market potential for CHP and CCHP and market penetration for a range of scenarios.
- Quantify the economic and environmental benefits of future CHP market penetration.
- Conduct analysis of incentive options including their costs and benefits to promote the CHP market opportunity
- Identify technology gaps and RD&D needs to meet identified market opportunities

Approach

The Commission entered into an R&D project with the Electric Power Research Institute (EPRI) to perform the work based on the pre-determined objectives and goals. EPRI assembled a project team consisting of:

- Energy and Environmental Analysis, Inc. (EEA)

- EPRI Solutions, Inc. (ESI-Primen)
- Energy and Environmental Economics, Inc (E3)

EEA conducted market analysis, ESI-Primen conducted market research; E3 developed alternative policy recommendations and quantified their costs and benefits; and EPRI provided an assessment of R&D gaps to improve CHP market penetration and performed overall project management. The overall research approach is illustrated in Figure 1-1.

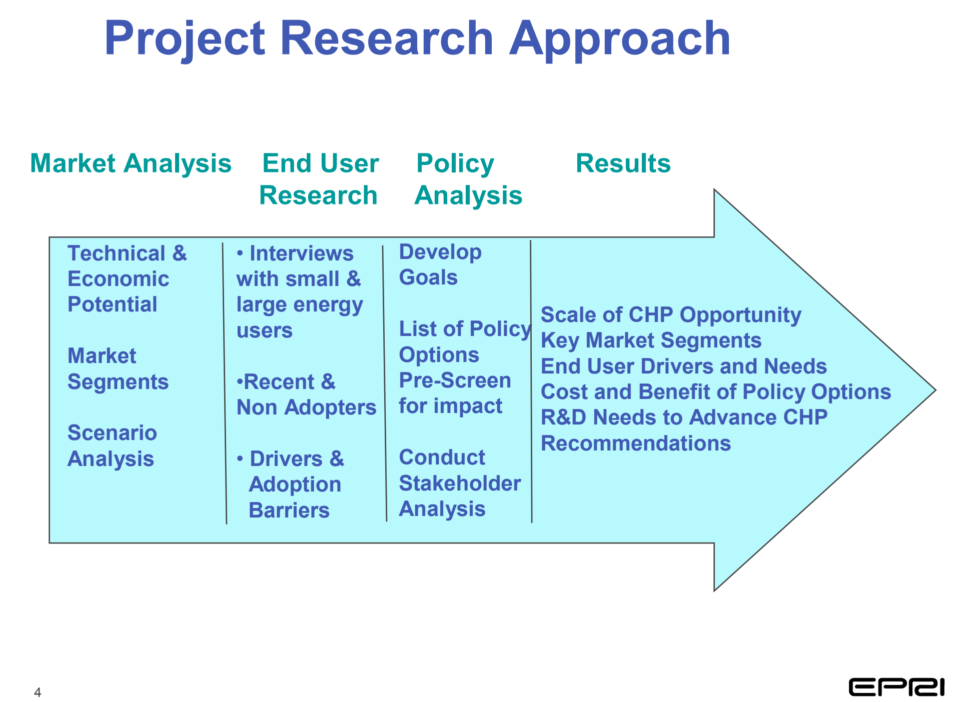


Figure 1-1
Project Research Approach

Report Organization

Results and findings from this research project are organized in subsequent chapters:

- The Executive Summary- provides an overall summary of the findings, key conclusions and recommendations
- Chapter 2 – Provides an analysis of the California CHP Market Analysis including the technical and economic potential
- Chapter 3 – Provides Market Research findings based on interviews and surveys from a segment of the state's end-users
- Chapter 4- Provides analysis of the various policy options (including costs and benefits) that could encourage CHP market penetration

- Chapter 5 – Provides analysis of R&D needs that could result in increased CHP market penetration
- Chapters 6 and 7 – Provide summaries of the overall conclusions and recommendations

Additional information, assumptions and documentation can be found in the Appendices.

2
CALIFORNIA CHP MARKET ASSESSMENT

Introduction

In terms of population, economic activity, and energy consumption, California is the largest state in the union. The welfare of the people of California depends on a healthy economy, which in turn depends on stable energy markets. Refineries, food processors, hospitals, hotels, government facilities, and any number of other activities out of the approximately 800,000 business establishments in the State need electricity and thermal energy to operate. Combining these needs into a single process whereby electricity is produced on-site and thermal energy is recovered and also used on-site can provide a number of benefits both to the user and to society. Combined heat and power (CHP), the subject of this market assessment, can provide the following benefits:

- Lower costs of facility operations contributing to higher productivity
- Protection from extended and momentary supply outages and brownouts
- Higher efficiency of energy use putting less pressure on energy supply markets
- Electricity capacity that can support resource adequacy needs of the electricity system
- Environmental benefits both in the reduction of criteria pollutants and emissions of carbon dioxide that contribute to global warming.

This chapter describes the market outlook for CHP in California. A model of the economic competition of CHP from the customer perspective was developed. The expected future market penetration of CHP (2005-2020) was determined assuming continuation of current polices. Several other scenarios were evaluated to test the impacts of potential policy measures, rate of technology development, and changes in customer response. The CHP market response is described in this chapter; the evaluation of alternative policy measures is described in Chapter 4.

Existing CHP Installations

There are already 9,130 MW of active CHP in California at 776 sites. Nearly 90% of this capacity resides in large systems with site capacities of over 20 MW.

The existing CHP was characterized as part of this study to aid in the identification of target markets both for the market penetration analysis and for the market research described in Chapter 4. Most importantly from an analytical perspective, this assessment seeks to identify remaining CHP potential in California. Therefore, the existing stock of active CHP installations has been subtracted from the technical market potential used in this analysis.

The largest share of active CHP capacity (**Figure 2-1**) is located in the oil fields to provide steam for enhanced oil recovery (EOR). Half of the total capacity is in the industrial sector and is heavily concentrated in five process industries: food processing, refineries, metals processing, pulp and paper, and chemicals. CHP in all other industrial sectors accounts for 7% of the total. The commercial and institutional sector represents 19% of the total capacity. While this commercial/institutional share is a small part of the California total, this market is comparatively well developed compared to the rest of the country; the commercial/institutional sector represents only 11% of total CHP capacity on a national basis.

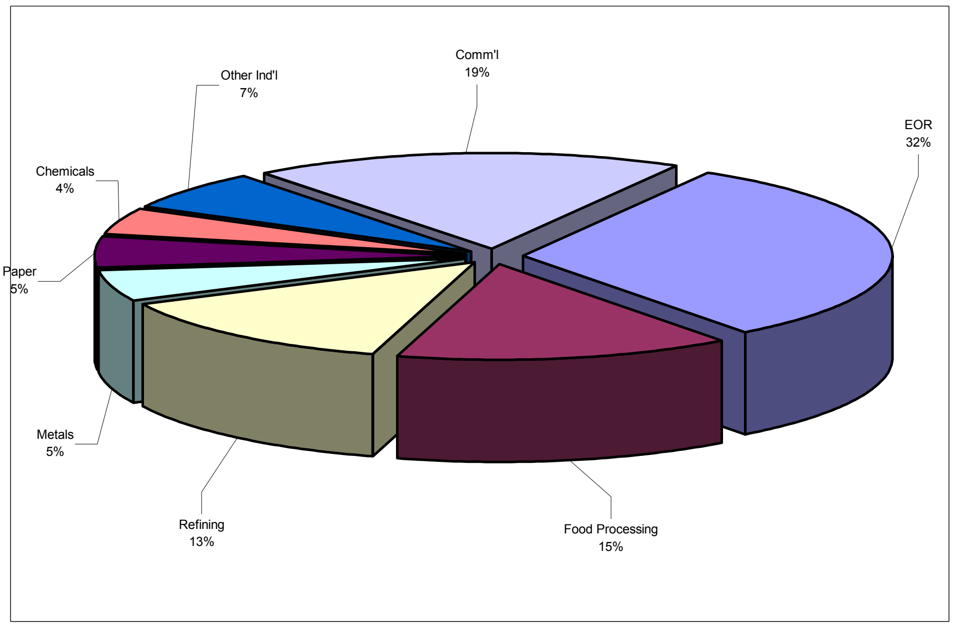


Figure 2-1
Share of California Active CHP by Application

The active CHP installations can also be characterized in terms of the size of the facility (**Figure 2-2**), the primary fuel utilized (**Figure 2-3**), and the type of prime mover (**Figure 2-4**).

- Large installations make up most of the existing capacity. Systems under 5 MW represent only 3.2% of total existing CHP capacity in California. Systems greater than 100 MW represent almost 40% of the total existing capacity. However, as will be shown later, the market saturation of CHP in large facilities is much higher than for smaller sites. Much of the remaining technical market potential is comprised of smaller systems.
- By far the most important fuel utilized for CHP is natural gas representing 84% of the total installed capacity. Renewable fuel makes up 4% of the total capacity with the bulk of this capacity in the wood products, paper, and food processing industries and in waste water treatment facilities.

- Given the concentration of large scale systems in the existing CHP population, the most common prime movers are gas turbines. In the very large sizes, these are often in combined cycle configuration. In intermediate sizes, simple cycle gas turbines are used. Renewable fuels or waste fuels are used in boilers driving steam turbines in the wood, paper, food and petrochemical industries. Most of the small systems are driven by gas-fired reciprocating engines; while total capacity is small (less than 3%), the reciprocating engine technology represents the greatest number of CHP sites (64%). Emerging technologies such as microturbines and fuel cells make up a small but growing fraction of systems.

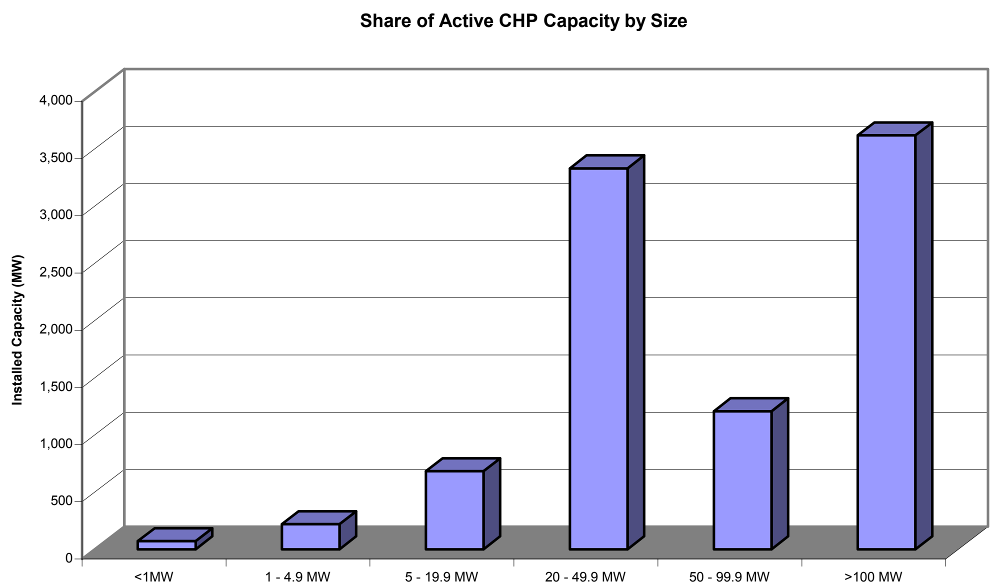


Figure 2-2
Share of California Active CHP by Facility Capacity

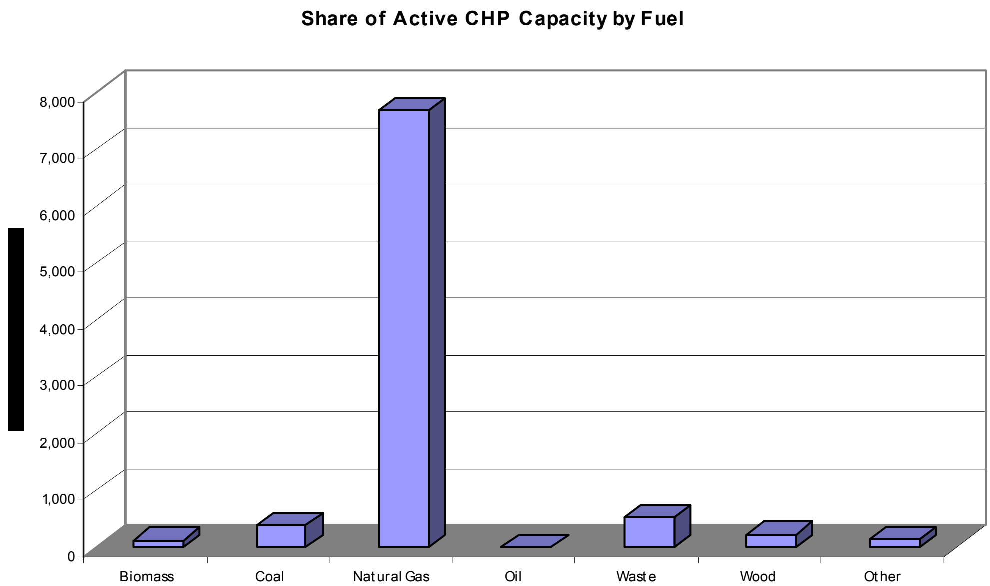


Figure 2-3
Share of California Active CHP Capacity by Primary Fuel

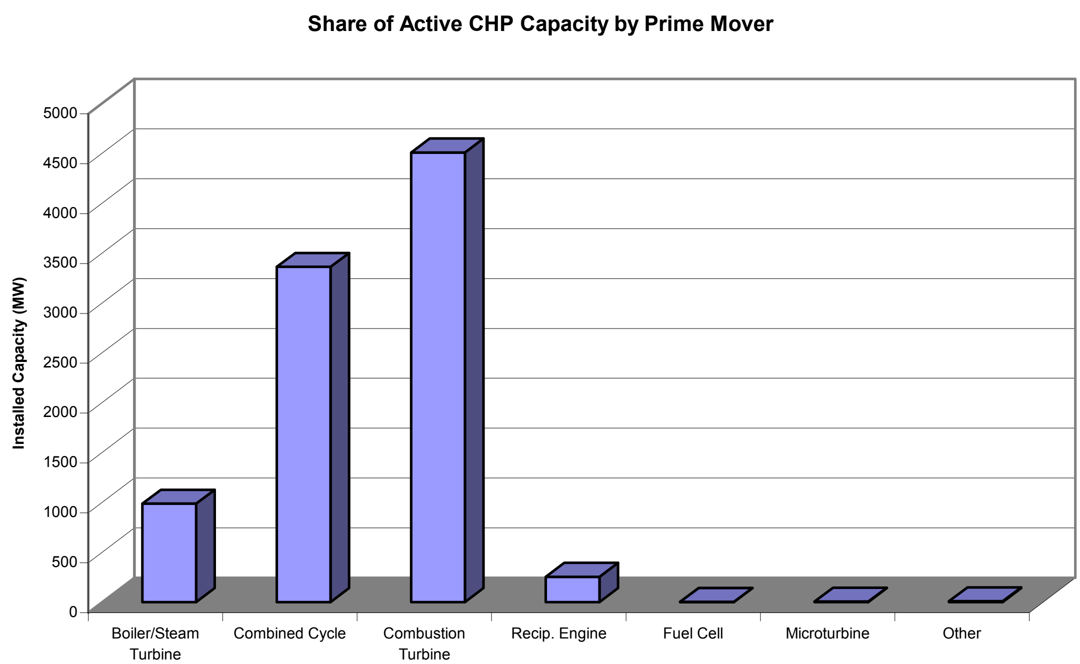


Figure 2-4
Share of California Active CHP by Prime Mover

A detailed profile of existing CHP is provided in **Appendix A.**

CHP Target Markets: Technical Market Potential

To effectively utilize CHP, a facility must have at least a portion of its electric and thermal load that coincides with the right ratio of thermal to electric energy. For best economic performance, this coincident thermal and electric load should be fairly steady for as many hours per year as possible. A continuous process industry with a nearly constant steam demand and electric load is an excellent target; a hospital with steady electric and hot water demands is a very good target. Facilities with intermittent electric and thermal loads are progressively less attractive as the number of hours of coincident load diminishes. The purpose of this market characterization is to identify the number and size of facilities in the State that provide the physical operating characteristics that are most likely to support an economic system. These target applications, called technical market potential, provide the input to the economic competition and market penetration model. Three different types of CHP markets were included in this evaluation:

- Traditional CHP – electric power is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:
    - High load factor applications – This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.
    - Low load factor applications – Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.
- CHP with thermally activated cooling (CCHP) – All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:
    - Low load factor applications – These represent markets that otherwise could not support CHP due to a lack of thermal load.
    - Incremental high load factor applications – These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system.
- CHP Export Market – The previous two categories are based on the assumption that all of the thermal and electric energy is utilized on-site. Within large industrial process facilities, there is typically an excess of steam demand that could support CHP with significant quantities of export electricity to the wholesale power system. The incremental export value of power from these facilities was quantified and evaluated as a separate market.

The technical market potential in these categories (detailed in Appendix B) was based on an evaluation of existing facilities in California with an estimate of future growth during the forecast period (2005-2020) based on adjusted historical sector growth rates (Appendix C.) The technical market potential for the traditional CHP market equals 14,381 MW in existing facilities and 5,793 MW from expected new facilities during the forecast period. **Figure 2-5** shows the remaining technical market potential for the industrial sector. The figure shows that the traditional top six process industries have already achieved a CHP market saturation averaging nearly 60%. Additional CHP market penetration in these industries contributes the majority of the remaining industrial market potential, but significant technical potential exists outside these industries.

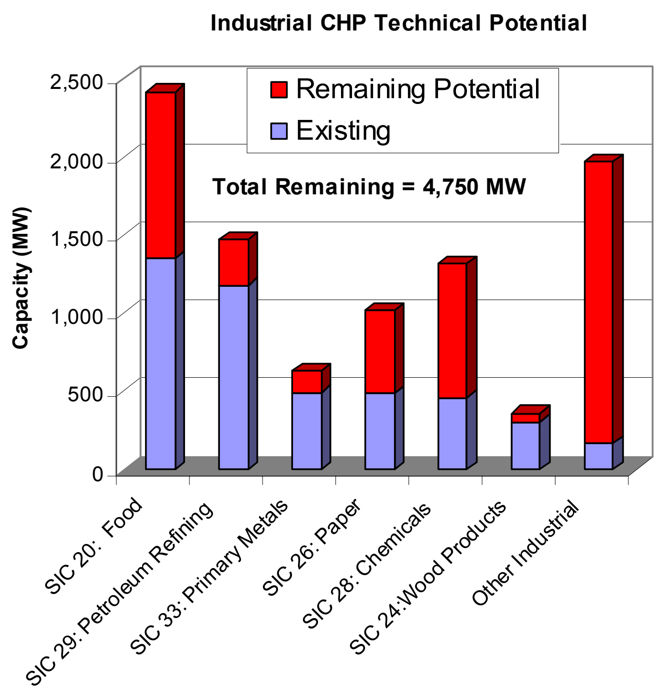


Figure 2-5
Industrial Technical Market Potential, Traditional On-site CHP, Existing Facilities

Two-thirds of the remaining technical market potential for traditional CHP is in the commercial/institutional sector. **Figure 2-6** shows that the top potential exists in education, offices[6], health care, and hotels.

[6] Offices represent a large share of commercial facilities. They tend to be limited in thermal load and hours of annual operation. These factors are considered in the economic analysis.

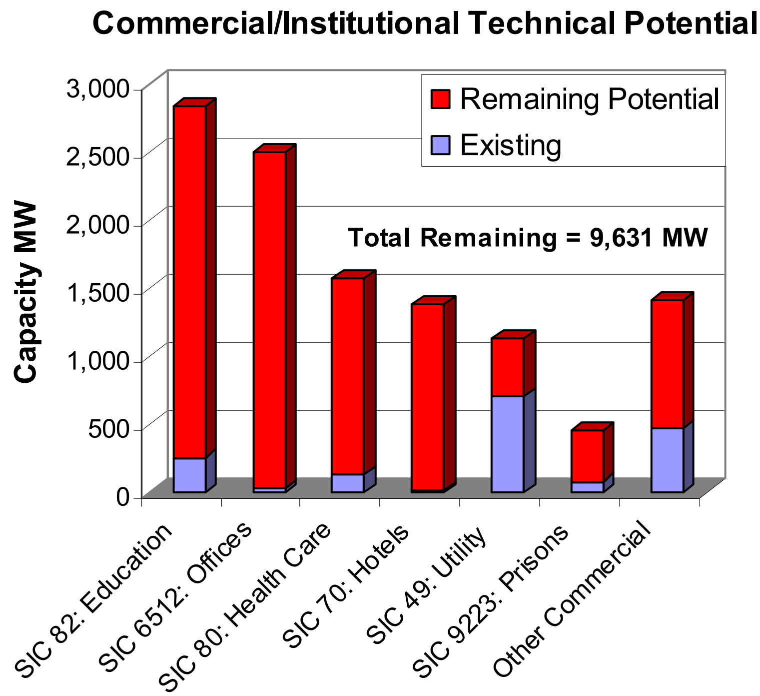


Figure 2-6
Commercial/Institutional Technical Market Potential from Existing Facilities

The cooling CHP market has a technical market potential of 5,405 MW. This potential includes both new applications that were not considered to be traditional CHP targets and incremental markets where cooling could be used to expand the capacity of traditional CHP. The new market, having a technical potential of 1,846 MW, consists of post offices, airports, movie theaters, big-box retail, food sales, and restaurants. The incremental markets include hotels, nursing homes, and hospitals. The total CCHP potential for this incremental market is 3,559 MW, though the net increase in the capacity already considered within traditional CHP is 1,025 MW.

The export market comes from the top one hundred industrial facilities in the state, characterized in terms, of steam demand. Most of this potential comes from a handful of very large refineries, chemical plants, and food processors. There is a total technical CHP export potential of 5,270 MW.

Considering all markets, including both existing and new facilities, there is a total technical market potential that approaches 30,000 MW (**Figure 2-7**.) The potential from new facilities expected to be added during the forecast period (2005-2020) is 25% of this total, though very little growth is expected in the export market that is concentrated in stable or declining industries with little if any growth potential.

It is important to quickly point out that 30,000 MW is not in any sense a market forecast for CHP under current or any reasonable set of assumptions. Technical market potential is intended to

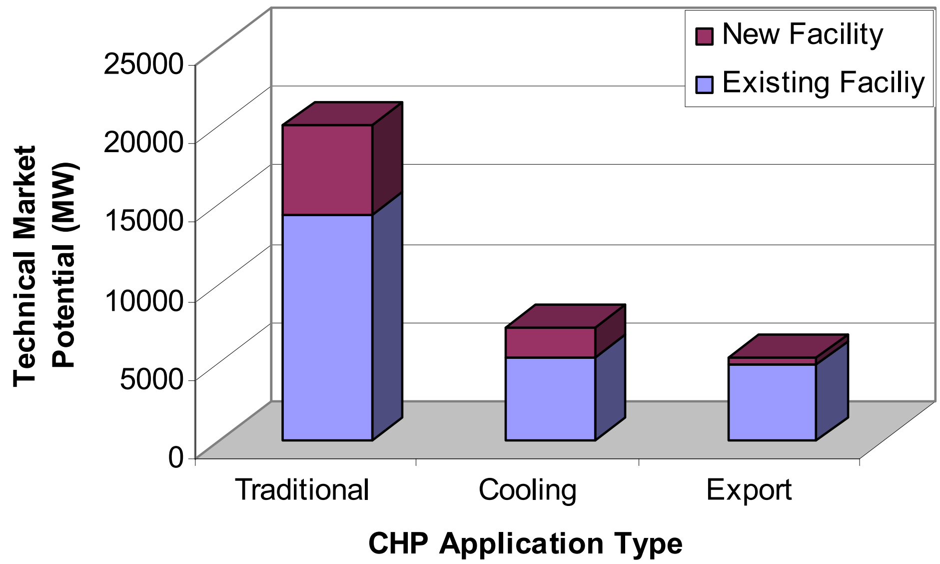


Figure 2-7
Total California CHP Technical Market Potential

represent the universe of potential applications upon which the economic screening and market penetration analysis is conducted. These markets represent the primary sales targets for CHP developers. However, if a developer were to approach one of these target facilities, any number of reasons might stand in the way of a CHP system ever being installed such as

- The facility might not have the loads expected
- The economics might not work out or the customer's investment criteria might be highly restrictive
- There might be site limitations such as lack of fuel availability or environmental restrictions
- The customer may be unable or unwilling to consider CHP.

These factors are considered in the economic competition and market penetration model.

Competitive Outlook for CHP

The outlook for CHP market penetration in California will depend on a number of factors:

- The relationship of delivered natural gas and electricity prices, or spark spread
- The cost and performance of the CHP equipment suitable for use at a given facility
- The electric and thermal load characteristics of commercial, industrial, and institutional facilities in the State
- Incentive payments, if any, to the CHP user that reflect societal or utility benefits of CHP

- Customer decisions about the economic value that will trigger investment in CHP or even the willingness to consider CHP at all.

This section focuses on three of these factors: energy prices, technology cost and performance, and customer behavior.

Natural Gas and Electricity Prices

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, determines the ability of a facility with electric and thermal energy requirements to meet these requirements cost-effectively using CHP.

Natural gas prices are at historically high levels. For this analysis, it was assumed that gas prices will decline over the next four years and then increase in real terms according to the 2003 IEPR high gas price case.[7] **Figure 2-8** shows the projected future track of gas prices.

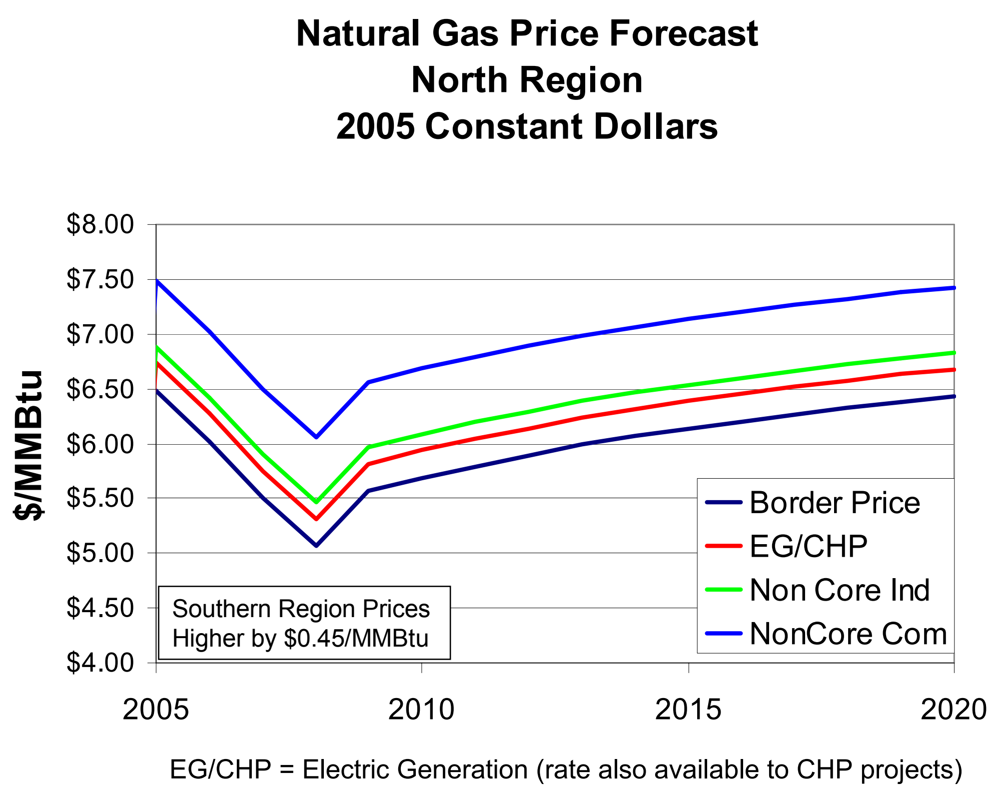


Figure 2-8
Projected Natural Gas Prices

California has high retail electric prices compared to the rest of the country. Efforts undertaken in the 1990s to restructure the electric industry to allow competition to bring about a phased reduction in power costs have produced unintended negative consequences to customer price and

[7] New forecasts of electric and natural gas prices are being made by the California Energy Commission as part of the 2005 Integrated Energy Policy Report. These new forecasts were not available for use in this study.

reliability and to the industry's financial viability. Additional changes to market structure to repair these consequences have been put in place. There is an expectation that the delivery related component of retail rates will continue to decline in real terms for the next five years and then grow with inflation (i.e., remain constant in real terms.) The generation component of electricity is affected by the natural gas price, so generation related charges are expected to follow the general decline and then increase shown in the previous figure. **Figure 2-9** shows the avoidable high load factor average electric prices by utility for large industrial and medium commercial markets. [8]

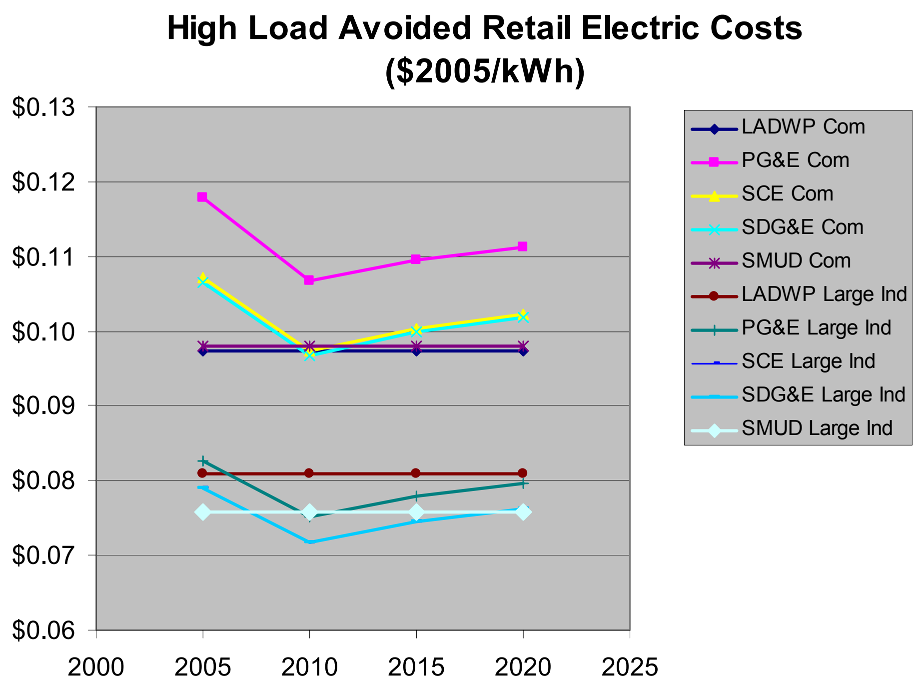


Figure 2-9
High Load Factor Average Avoidable Electric Price Forecast

Retail electric customers of the three IOUs with CHP must pay departing load customer responsibility surcharges (CRS), though there are a number of exemptions that reduce this amount for customers with CHP systems that meet specified efficiency and emissions targets or are eligible under the Self Generation Incentive Program. All CHP customers must pay nuclear decommissioning and public purpose programs charges. Customers with qualifying CHP are not required to pay the Competitive Transition Charges. Customers with CHP greater than 1 MW must also pay the DWR Bond Surcharge, whereas customers with qualifying CHP system below this size are exempt. These surcharges for CHP customers typically are under 5 mills/kWh for customers with CHP under 1 MW and under 1 cent/kWh for larger CHP customers; the charges must be paid on the departing load, that is the entire output of the CHP system. LADWP has completely distinct rates for generating and non-generating customers, and as such effective standby charges are much higher.

[8] The avoidable rate is calculated based on saving 95% of the energy charges and 10 out of 12 months for unratcheted demand charges and no avoidance of ratcheted facility demand charges.

Detailed gas and electric price forecasts are shown in **Appendix D**.

CHP Technology Cost and Performance

The CHP system itself is literally the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the cost of meeting the electric and thermal loads. A variety of appropriate technologies were allowed to compete for market share. In the smaller market sizes, internal combustion engines (ICE) competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), ICEs competed with gas turbines and at the small end of the range with the larger fuel cell systems. Large systems, over 20 MW, utilized gas turbines and very large installations could utilize combined cycle plants.

Figure 2-10 compares the net power costs for the competing systems in each size range. Net power cost is defined as the cost of producing power on-site including the annual capital charges for the equipment, the net fuel required after avoided boiler fuel is subtracted, and the non-fuel operating and maintenance costs. The figure shows that, in general, the net cost of producing on-site power goes down as the size of the system increases. For the base case, emerging technologies (fuel cells and microturbines) are not very competitive with either ICEs or retail power costs. These assumptions were designed to reflect a most likely case upon which to test a variety of policy measures. There are development targets for these technologies that are much lower than what was assumed here. The fact that these development targets are not used as the most likely case for this analysis, should not be taken as a conclusion regarding the ability of fuel cell and microturbine manufacturers to reach much lower cost goals.

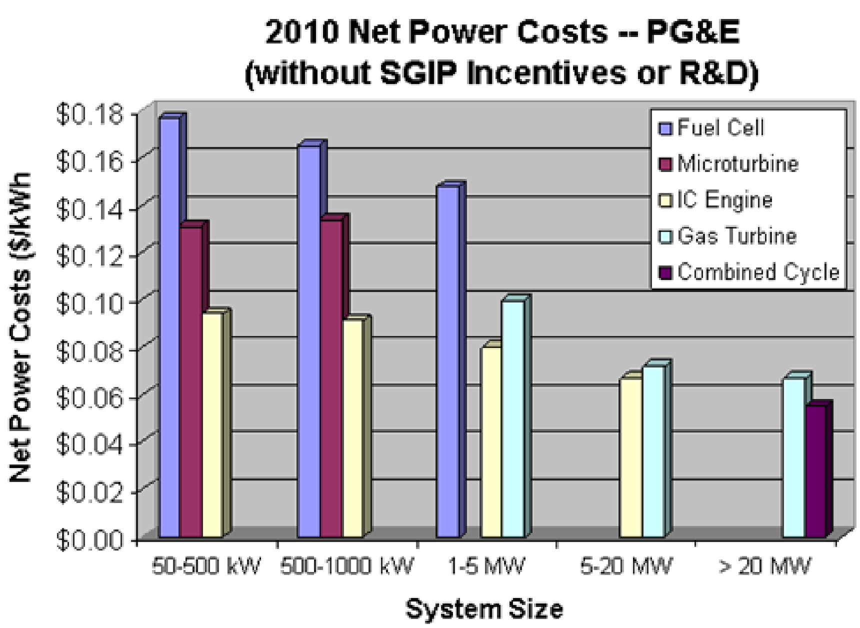


Figure 2-10
Net Power Costs by System Size and Technology

The details of the technology cost and performance assumptions are provided in Appendix E.

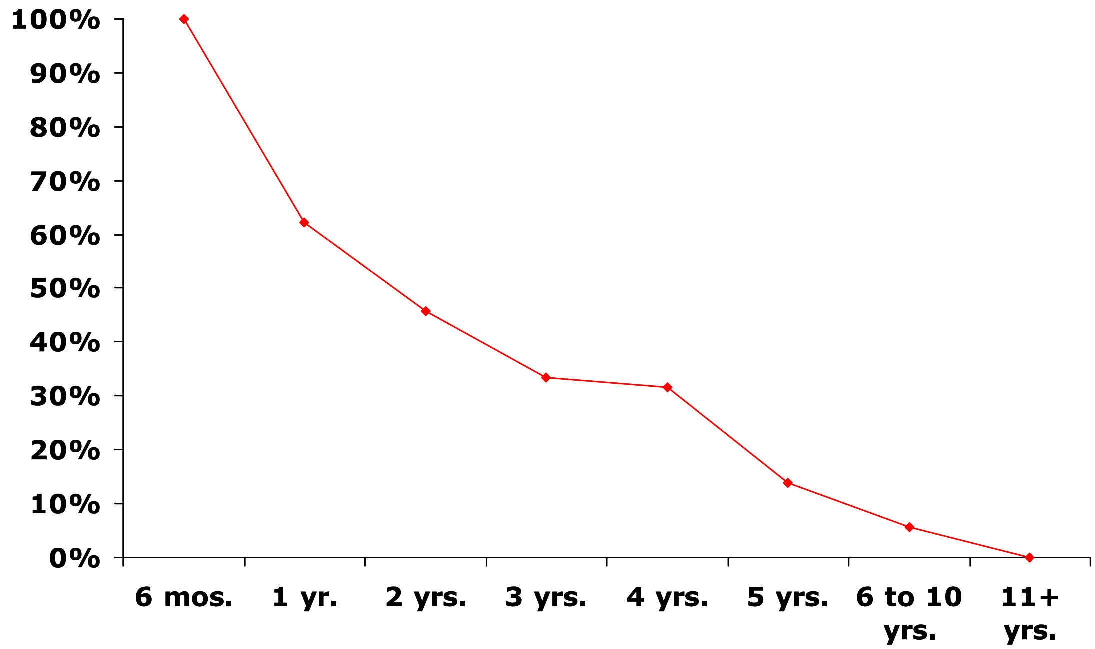
Consumer Decision Factors

The 30,000 MW of technical market potential identified was screened only with respect to the fact that the particular applications were likely to have the operating conditions necessary to support a high load factor CHP system. An additional screening factor was applied to reflect the share of each market size bin within the technical potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 60% in the largest size bin (more than 20 MW.) These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from iMarket.

Among the customers that will consider CHP, the expected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. The economic figure-of-merit chosen to reflect this competition in the market penetration model was simple payback.[9] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers. In addition, all of the CHP projects have similar operating lives and cost structures making it likely that payback is very highly correlated with more detailed financial measures based on discounted cash flow analysis (net present value, return on investment, return on equity).

Figure 2-11 shows the response of a cross-section of commercial and small industrial customers to a recent market survey concerning the payback that would be required for a distributed energy project to be accepted for investment. As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year! A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. The only explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

[9] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.



Source: *Primen's 2003 Distributed Energy Market Survey*

Figure 2-11
Customer Payback Acceptance Curve

An approximation of this payback acceptance curve was used as the basis of determining the share of the market that would install CHP based on the calculated paybacks within each region/utility/size market bin.

For the export market, it was assumed that there would be a much higher acceptance of projects that had paybacks higher than the average California IPP ROI requirement of 16% equivalent to about a 5-year payback. In the export market, projects with a 2-year payback or less produced a 100% acceptance rate declining linearly to 40% acceptance at a 5-year payback and zero market acceptance for paybacks longer than 5 years.

A more complete discussion of the economic competition and market penetration model is provided in **Appendix F**.

CHP Market Penetration: Base Case Forecast

The energy prices, technology cost and performance characteristics, and consumer behavior described in the previous chapter were used in the market penetration model. Existing incentives for CHP were also included to form the base case market forecast. The base case forecast contains the following policy assumptions:

- Self Generation Incentive Program (SGIP) payments for the first 1 MW of qualifying systems under 5 MW of capacity are available through 2014. These payments help to offset the initial capital cost of small CHP systems. The payments vary by fuel use and technology. For natural gas fired systems the payments are $600/kW for reciprocating engines, $800/kW for microturbines, and $2,500/kW for fuel cells. Approximately $112 million per year has been allocated to this program.

- CHP systems meeting minimum thermal use and efficiency standards receive an incentive gas price based on the electric generation rate.[10] This lower rate not only increases the basic gas/electric spark spread but it also provides an additional benefit based on the avoidance of the use of higher-priced gas used to meet the facility's thermal loads.
- As previously stated, there are CHP related exemptions that reduce the CRS payments by 4-10 mills/kWh. These reductions are built into the price analysis.
- Customer response to CHP paybacks is based on reported relationships described previously in Figure 2-11.

No CHP export was assumed in the base case due to a lack of enabling policies that provide wholesale market access and pricing.

Based on these assumptions, there will be a cumulative market penetration (2005-2020) of 1,966 MW of additional CHP capacity. **Figure 2-12** shows cumulative market penetration in 5-year increments by individual market sector. **Table 2-1** shows the cumulative market penetration by the end of the forecast period by utility.

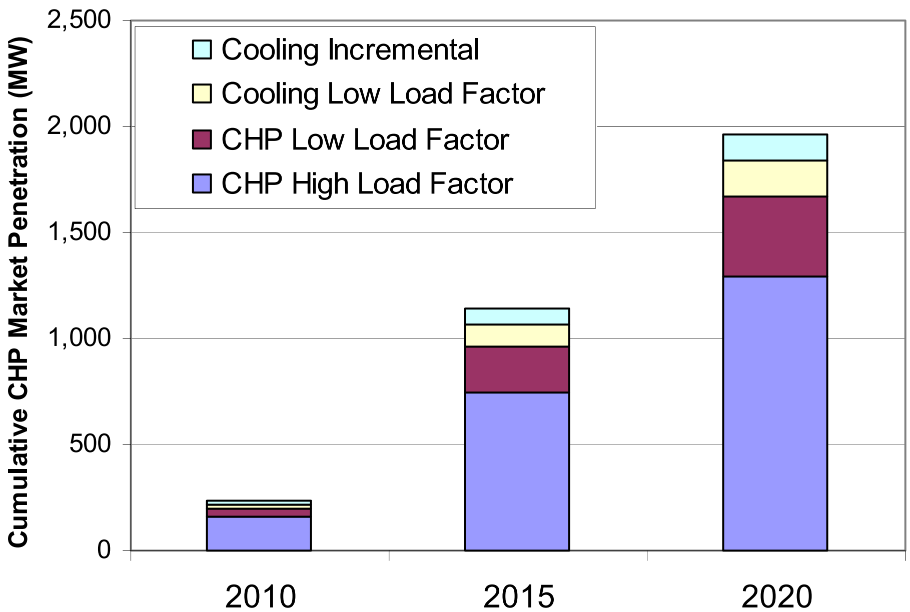


Figure 2-12
Base Case Cumulative Market Penetration Statewide

[10] Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 218.5 are entitled to the electric generation transportation rate. : In accordance with the code, at least 5 percent of the facility's total output must be in the form of useful thermal energy. Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output must equal no less than 42.5 percent of any natural gas and oil energy input.

Table 2-1
Base Case Cumulative Market Penetration (2005-2020) by Size and Utility

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	167	239	286	72	74	839
	SMUD	8	14	18	5	0	45
	Other North	2	3	3	0	0	8
North Total		178	256	306	77	74	891
South	LADWP	7	5	14	5	15	47
	SCE	155	181	318	60	133	847
	SDG&E	28	39	63	6	18	155
	Other South	6	6	11	4	0	27
South Total		196	231	406	76	167	1,075
Grand Total		373	487	713	153	241	1,966

The base case results can be further characterized as follows:

Market penetration in the first five years is very low adding only 234 MW of CHP capacity.

- Overall market penetration at less than 2,000 MW is about half that of a 1999 forecast that was based on gas prices that were much lower than the current forecast.[11] The high level of gas prices makes competition more difficult for CHP with correspondingly longer paybacks and lower acceptance levels among potential adopters.
- Market penetration of fuel cells and microturbines remains very low throughout the forecast period due to uncompetitive early market pricing that is not offset by the SGIP payments.
- Reciprocating engine systems, the dominant technology in markets less than 5 MW, are unable to meet the accelerated 2007 emissions requirements in Southern California until 2010. In addition, small gas turbines will require very expensive after-treatment until that technology improves. Consequently, there is no market penetration in Southern California during the first 5 years for systems less than 20 MW.
- Cumulative market penetration ranges from 6 to 8% of technical market potential for sizes less than 20 MW; for systems larger than 20 MW, cumulative market penetration equals 23% of technical market potential.
- Market penetration rates in LADWP service territory are much lower due to a combination of slightly lower rates and a special generating rate that reduces the share of a customer's bill that can be saved by self generation.
- The difficulty in selling excess electricity from a CHP generator leaves the 5,200 MW potential market untapped. The market requires scheduling hour by hour exports with the CAISO, and finding an electricity buyer. A policy that encourages the utilities to purchase electricity from CHP as delivered at the prevailing wholesale price could address this

[11] *Market Assessment of Combined Heat and Power in the State of California*, prepared by Onsite Sycom Energy Corporation, California Energy Commission Report P700-00-009, July 1999 (released October 2000.)

problem and encourage larger CHP installations in facilities which use significant amounts of thermal energy. This could look like 'net metering' at the wholesale energy price.

- Of the total 1,966 MW cumulative market penetration in the base case, 606 MW is in a combined heating and cooling configuration. These systems save an additional 70-90 MW of peak electric capacity by displacement of electrically driven air conditioning.
- The base case provides total benefits over the 15 year forecast period of 400 trillion Btu of energy savings, close to one billion in reduced facility operating costs, and a CO2 emissions reduction of 23 million tons.

Alternative Policy Case Forecasts

A number of other forecast scenarios were considered to test the market penetration of alternative policy variables. These cases are summarized in **Table 2-2**.

Table 2-2
Alternative Forecast Scenario Results

Scenario	Onsite CHP MW	Export CHP MW	Total Market Penetration MW	Description
Base Case	1,966	0	1,966	Expected future conditions with existing incentives
No Incentives	1,141	0	1,141	Remove SGIP, CHP incentive gas price, and CHP CRS exemptions)
Moderate Market Access	1,966	2,410	4,376	Facilitate wholesale generation export
Aggressive Market Access	2,479	2,869	5,348	$40/kW year T&D capacity payments for projects under 20 MW, global warming incentive, and wholesale export
Increased (Alternative) Incentives	2,942	0	2,942	Extended SGIP (incentives on first 5 MW for projects less than 20 MW, $0.01/kWh CHP production tax credit
Streamlining	2,489	0	2,489	Customer behavior changes: higher response to payback levels and greater share of market that will consider CHP
High R&D on Base Case	2,764	0	2,764	Rate of technology improvement accelerated 5 years
High Deployment Case	4,471	2,869	7,340	Accelerated technology improvement with aggressive market access and streamlining to improve customer attitudes and response

Each of these scenarios is summarized in this chapter in terms of the assumptions and key results. Detailed results of each scenario are presented in **Appendix G.**

No Incentives

No Incentives Case Assumptions

The no incentives case evaluates the economic potential of CHP if all current incentives are removed. As previously described, there are three factors considered: the SGIP payments, the incentive CHP gas price, and the customer responsibility surcharges (CRS) exemptions. The no incentives case is designed to put the impact of current policy in perspective.

No Incentives Case Results

Cumulative market penetration falls to 1,141 MW in the *no incentives* case, a 42% reduction compared to the base case.

Of particular interest is the separate reduction due to removal of the SGIP program. Under the base case, 678 MW of capacity receive SGIP payments at a cost of $402 million.[12] However, the net difference in the base case and a scenario with the SGIP program removed is only 346 MW.

The incremental impact of removing the incentive CHP gas rate (after removal of the SGIP) is comparatively much smaller at only 114 MW of cumulative market penetration.

The elimination of the CHP related CRS exemptions reduce market penetration by 364 MW.

Moderate Market Access

Moderate Market Access Assumptions

The *moderate market access* scenario allows facilities to export power at the wholesale energy price. An annual average levelized wholesale energy price of 6.6 cents/kWh was projected based on the natural gas forecast and the cost and performance of a new CCGT (see Appendix D). The technical potential for this export market is largely concentrated in very large facilities – over 100 MW per site.

Moderate Market Access Results

An additional 2,410 MW of cumulative market penetration is added to the base case results. This export market potential is entirely comprised of very large combined cycle power plants. Smaller industrial facilities with export potential are unable to earn an economic rate of return at the assumed wholesale price.[13]

When combined with the base case on-site CHP market penetration, the expected future CHP market is more than doubled. Facilitating the export market would be very effective in stimulating the near-term market; the expected CHP capacity additions in the first 5 years would increase from 234 MW to 1108 MW.

[12] The 678 MW is based only on the capacity that actually qualifies for the incentive payment, that is, the capacity that is less than or equal to 1 MW. However, since the incentive is paid on the first MW of all systems less than 5 MW, the total capacity that enters the market receiving either full or partial incentive payments is equal to 929 MW.
[13] Export projects were required to have a minimum 18.4% internal rate of return for customer acceptance the equivalent of a 5-year payback. Paybacks in the 5-20 MW size bin were in the 6-8 year range. Such paybacks, as shown in Figure 2-11, provide small levels of project acceptance for onsite projects but not for export projects.

Aggressive Market Access

Aggressive Market Access Assumptions

The *Aggressive Market Access* case includes two new incentive programs in addition to the ongoing incentives considered in the base case and the facilitation of the export market as shown by the *moderate market access* case. A CO_2 reduction credit equivalent to$8/ton is assumed for CHP. The basis of this credit is the net reduction of CO_2 emissions for the CHP system compared to an assumed level of emissions for the avoided electricity and boiler fuel. **Figure 2-13** shows an example basis of this calculation.

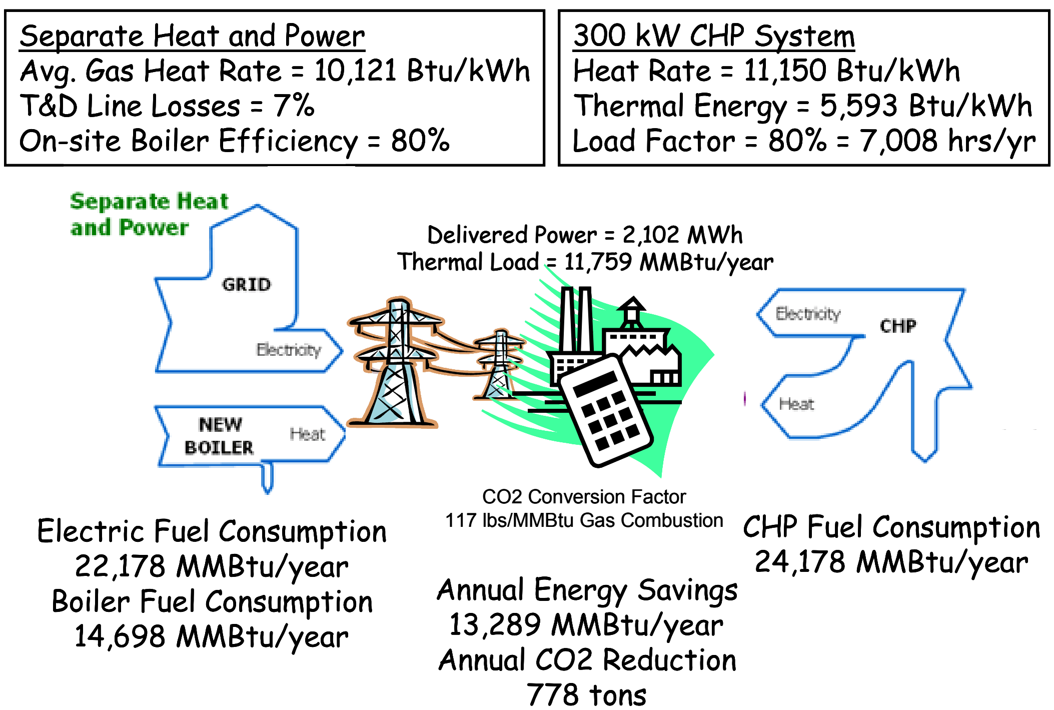


Figure 2-13
CO_2 Reduction from CHP

A further incentive assumed in this case is the addition of a T&D benefit payment of $40/kW-year. In the model, this payment is made to all systems less than 20 MW. T&D benefits are a localized issue, so not all systems would provide benefits or receive a payment. However, the $40/kW-year figure was chosen to reflect an average payment across all CHP systems being deployed. A more complete discussion of this incentive is provided in Chapter 4.

Aggressive Market Access Results

The addition of the CO_2 reduction incentive and the T&D capacity payment provides an increase in cumulative market penetration compared to the *moderate market access* case of 972 MW.

The increase in the on-site CHP market of 513 MW is roughly 2/3rds due to the T&D payment and 1/3 due to the CO_2 reduction payments. The export market change is mostly due to the CO_2 reduction payments because it was assumed that the T&D capacity payments did not apply above 20 MW for systems that feed directly into the transmission system. T&D capacity payments are applied to the small penetration of export systems in the 5-20 MW size bin, and do result in the addition of 115 MW of export capacity. These systems were assumed to qualify for both the CO_2 and T&D incentive payments.

Increased Incentives Scenario

Increased incentives Assumptions

In the *increased incentives* case, the base case was modified as follows:

- The SGIP program was expanded to make payments on the first 5 MW of projects up to 20 MW in size

A production tax credit of $0.01/kWh of CHP output was added

These incentives represent alternative incentives for CHP; they are not added onto the *aggressive market access case* incentives.

Increased Incentives Results

The cumulative market increase for on-site CHP equals 946 MW over the base case.

The SGIP cumulative program cost increases from $402 to $921 million. The production tax credit costs a cumulative $994 million.

There is a stimulation of microturbine and fuel cell market penetration, though without modeling significant technology improvement, these emerging technologies combined only take about a 10% market share compared to packaged reciprocating engine systems.

Streamlining Scenario

Streamlining Assumptions

The *streamlining* scenario considers changes to consumer behavior based on increased awareness, education, training, and market confidence. The changes considered are a liberalization of the payback acceptance curve (Figure 2-11 shown previously) and an increase in the share of customers within each market segment that would be willing to consider CHP at all.

It was assumed that increased awareness and confidence in CHP technology and successful implementation in related businesses would encourage customers to accept projects with somewhat longer, but still economic, paybacks. The response rate was shifted by about 1 to 1.5 years as shown in **Figure 2-14.** In other words, in the previous relationship, just under half of people said they would accept a distributed energy project that had a 2-year payback, only about 35% said they would accept a 3-year payback. In this case, these acceptance levels are shifted such that 50% accept a 3-year payback and 35% accept a 4-year payback.

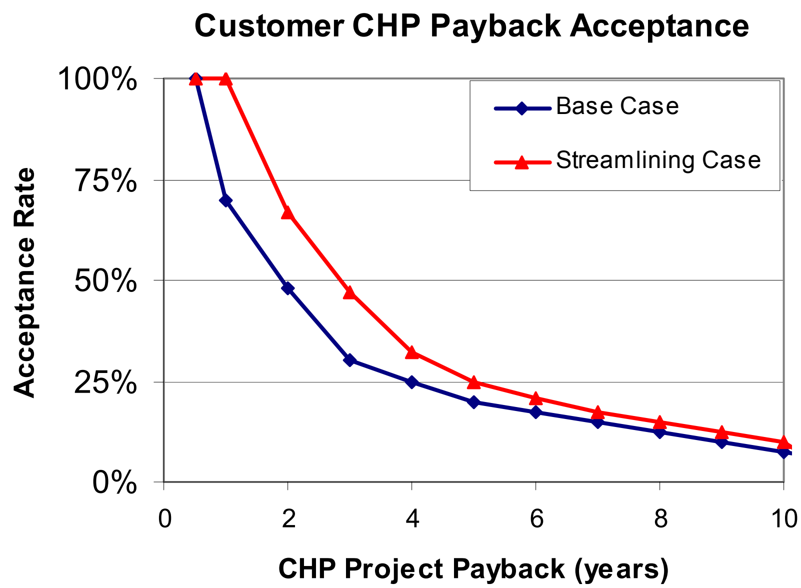


Figure 2-14
Customer CHP Project Acceptance Criteria

The second change assumed was that more of the market would consider CHP. In the base case, it was assumed that only a fraction of the total technical market potential would be open to consider CHP. Part of this restriction reflects the fact that there are factors that could eliminate a facility from consideration that were not addressed by the screening process and part reflects factors that could be changed such as willingness to consider CHP, better availability of credit or third-party financing. In the base case the share of the markets that were assumed to consider CHP ranged from 32% in the small sizes increasing incrementally to 60% of the market over 20 MW. These assumptions were changed to a range of values from 39%-64%. It was assumed that streamlining would be much more effective at improving participation in the small sized equipment market than in the larger markets where facilities typically have greater understanding of CHP opportunities and issues already.

Streamlining Results

Allowing more of the facilities within the technical market potential to consider participation in the CHP market increased market penetration by about 16%. Changing the payback acceptance relationship only increased the market by about 10%. The reason for the limited response to liberalizing the payback response function was that the biggest increase in acceptance occurs for paybacks of less than 3 years. In the base case, the very best paybacks for CHP tended to be in the 3.5-5 year range, so the resulting improvement in customer response was fairly minor.

High R&D Scenario

High R&D Assumptions

The base case technology cost and performance assumptions were based on a slow rate of improvement over time consistent with manufacturer improvements in the absence of significant public sector research and development (R&D.) In the *High R&D* case, technology improvements are assumed to be accelerated by 5 years as a result of public investment in the technologies. Other than the assumption of increased R&D, none of the policy incentives from either the *aggressive market access* or the *increased incentives* cases are included in this scenario.

High R&D Results

Over the entire forecast period this case increases cumulative market penetration by 798 MW. Accelerated technology improvement is particularly effective in bringing more systems into the market in the first five years. The five year cumulative market penetration more than doubled to 511 MW compared to the base case. The primary reason for this increase is that accelerated technology development allowed economically competitive reciprocating engine systems to meet the very stringent 2007 emissions limits within the first five years of the forecast period.

The improvement in the fuel cell market penetration is very dramatic while the SGIP is active. Improved performance coupled with an incentive payment of $2500/kW for fuel cells results in a huge increase in fuel cell market penetration from just 46 MW in the base case to 627 MW in the high R&D case. This increase raises the SGIP cumulative payments from $402 million to $1.9 billion. (No cap was modeled.) After the SGIP program ends, fuel cell market penetration returns to very low levels. If the incentive payment for fuel cells were reduced more in line with that paid to reciprocating engines and microturbines, there would be only a slight reduction in overall market penetration, but 90% of the fuel cell market share would be replaced by reciprocating engines and microturbines.

There was no technology acceleration assumed for large combined cycle power plants. Therefore, the export market would remain unchanged from the base case.

High Deployment Scenario

High Deployment Assumptions

The *high deployment* scenario is a combination of three cases. *High R&D* is combined with the *aggressive market access* incentives and the improved customer response rates modeled in the *streamlining* case.

High Deployment Results

There is a synergistic effect of combining each of the measures described compared to the market effects of each of the measures individually. The individual impacts of separately considering accelerated technology, aggressive market access, and streamlining would create a scenario with a cumulative market impact of 6,669 MW. However, when taken all together these measures produce a cumulative market response of 7,340 MW, or about 10% higher.

When the improved technologies are combined with increased incentives, project paybacks are pushed into the 2-3 year range where the increased market acceptance rates have the most impact.

The high deployment case greatly increases the cumulative benefit measures compared to the base case, energy savings increase from 400 to 1,900 trillion Btu, customer net reduction in energy costs increases from $1 billion to $6 billion, and CO2 emissions reduction increases from 23 to 112 million tons. The cooling component of the CHP market increases to 1094 MW which provides an additional 130-170 MW of summer peak load reduction.

Penetration of fuel cells is very high in this case, 1100 MW by the end of the forecast period, and almost all of this capacity is added as a result of the very high SGIP incentive for fuel cells. This degree of market penetration puts extreme pressure on SGIP resources. Again, no cap was put on spending for this program in the model, so payments increase sevenfold.

Sensitivity of CHP Market Penetration to Key Variables

Stable natural gas prices are critical to the success of a CHP project. Generally, a project cannot get financing without a long-term gas contract, in order to eliminate a major component of project related risk. The scenario analysis was all done with the same gas price forecast, so this section describes the sensitivity of market penetration to changes in gas price.

Without making corresponding changes to electric prices, there is a very elastic CHP demand response. If gas prices go up or down by 10% across the board, cumulative market penetration varies inversely by plus or minus 17% shown in **Figure 2-15**. However, gas prices do have an impact on the generation component of electric rates. In the last five years, natural gas generation within the State has supplied between 30 and 42% of California's total electricity supply. Using the median value of 36% of California's generation is fueled by natural gas as the basis for determining the natural gas/electric price interaction, provides a relationship where CHP market penetration varies by about 7% for a 10% change in gas prices. In fact, in a system where gas supplies 70% of the generation as shown on the figure, the relationship between CHP market penetration changes from negative to positive – an increase in gas price results in a slight increase in CHP market penetration. The more dependent the electric system is on gas-fired generation, the less of an impact there will be for changes in gas prices.

Market penetration is also very sensitive to the capital cost of CHP equipment. **Figure 2-16** shows the sensitivity of cumulative market penetration (base case) to changes in the capital cost of CHP equipment. Market penetration varies inversely with CHP capital cost. A 10% change in capital cost produces a 12-13% change in market penetration. The positive impact on market penetration increases as capital cost decreases get larger. This is due to the improved project paybacks bringing much more customer acceptance at lower paybacks.

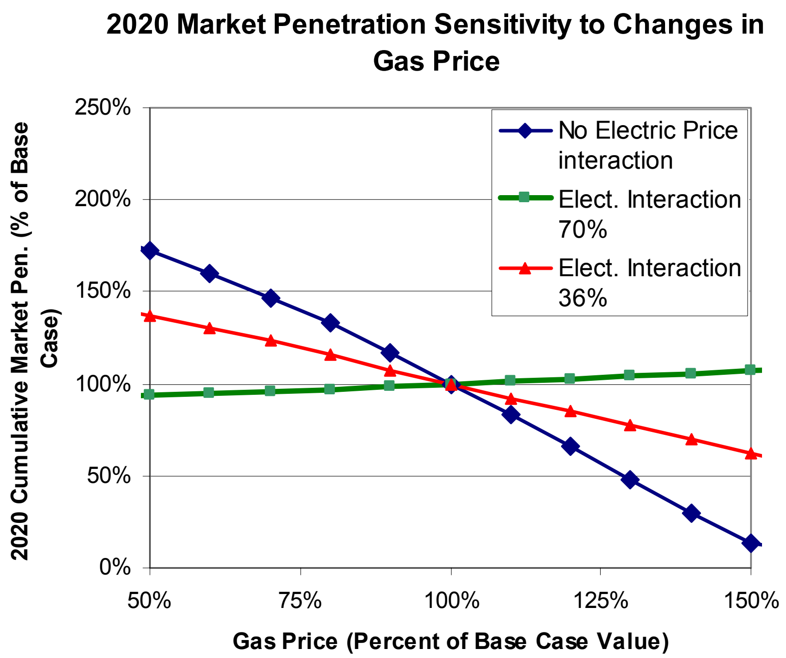


Figure 2-15
Sensitivity of Market Penetration as Function of Changes in Gas Prices

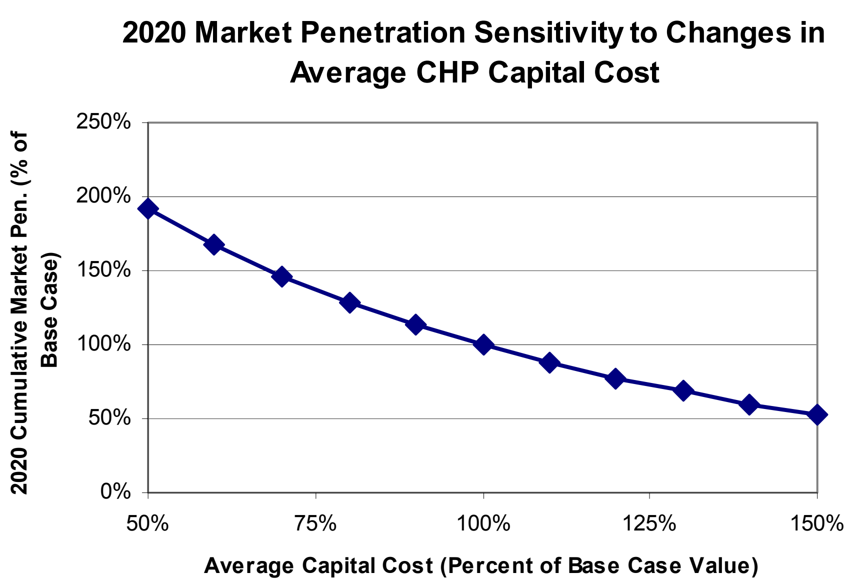


Figure 2-16
Sensitivity of Market Penetration as Function of Changes in CHP Capital Cost

3
MARKET RESEARCH - VOICE FROM CALIFORNIA'S END-USERS

One of the objectives of this report is to assess energy users' receptivity to CHP and investigate those policies that if enacted, would be likely to increase energy user adoption of CHP.[14]Using results from both recent nation-wide primary market research on energy users and a series of newly conducted in-depth interviews with California energy users who have adopted CHP or considered adopting CHP, we conclude that California energy users:

- Value CHP for the energy cost savings and for the enhanced reliability that they perceive CHP provides them
- Accept a payback on CHP projects at a rate similar to national averages, that being less than half of the establishments saying that a payback period of two years is acceptable
- Find significant barriers to adopting CHP, including longer than acceptable paybacks (resulting from high capital costs, natural gas prices, and interconnection charges) and low prioritization from upper management
- Favor new government policies that would address project economics, including an expansion of the SGIP to include projects up to 20 MW and incentives for up to 5 MW of each project and measures to allow CHP owners to sell power back to the grid.[15]

The remainder of this chapter describes the market research methodology and findings in greater detail.

Research Method

In order to identify which policies would be effective in encouraging CHP in California, a thorough understanding is needed of what drives energy users to add CHP to their facility and of the obstacles they encounter. To build this understanding we began by leveraging existing national survey data on energy users' views of CHP. We then conducted in-depth interviews with 20 California-based energy users and three California developers of CHP projects – both to verify the results of the national surveys and to expand the depth of questioning to specific policy options for California.

[14] We use CHP to include both combined heat and power (CHP) as well as combined cooling, heating and power (CCHP).

[15] The findings from this research on energy users' policy preferences have been incorporated into the policy menu and scenario analyses for this project.

Leverage Existing Survey Data

Three years of Primen's Distributed Energy Market Studies provided insight on the drivers of adoption for CHP/CCHP. Each year, between 600 and over 800 facilities ranging in size from 10 kW to 10MW nationwide were surveyed. A significant portion of the facilities surveyed was located in California. Table 3-1 shows the breakdown for each year's survey.

Table 3-1
Existing National Survey Data Mined

Year	Total Sample	CA Sample	Sectors Included	Facility Sizes
2003	806	55	All sectors except agriculture, mining & construction	100 kW to 10MW
2002	600	83	Continuous process mfg, heat recovery & highly PQ sensitive segments	300 kW to 10 MW
2001	627	66	Continuous process mfg, heat recovery , highly PQ sensitive segments, & opportunity fuels	10 kW to 5 MW

Information collected from these surveys was used to determine the drivers and barriers for energy user adoption of CHP in California. These surveys provided information on the likelihood of purchasing onsite generation for base load application, the maximum length of acceptable payback period for base load generation purchase, and drivers and barriers for onsite generation.

Interview California End-Users

To verify and support the results from the existing market surveys, we conducted 20 in-depth interviews with California energy users. These respondents represented organizations that since 2001 had either adopted CHP or considered adopting CHP at their California facilities but had not done so yet. The non-adopters had either put their plans on hold, are still in the decision-making mode, or chose not to proceed with the project. Our sample focused on users with average electricity demand of between 500 kW and 25 MW. Table 3-2 shows the original sample plan as well as the actual breakdown of completed interviews.

Table 3-2
In-depth Interview Sample Plan

Criteria	Quota	Actual
Non-adopter	12	11
Adopter	8	9
Small facilities (500 kW to 4 MW)	8	12
Larger facilities (4 MW to 25 MW (or greater))	12	8

Although the sample plan did not specify a regional breakdown, we aimed to split the interviews equally between Northern and Southern California because of differences in energy prices, local utility company, and the local air districts. In the end, we completed 12 interviews with facilities located in Northern California and 8 in Southern California. Table 3-3 provides more specific details on the 20 energy users that we spoke with.

Table 3-3
List of In-Depth Interview Respondents

Company Type	Size of System (installed or considered)	Adopter/ Non-adopter	Northern/ Southern CA
Brewery	1 MW	Adopter	Northern
College	14.3 MW	Adopter	Southern
College	12.5 MW	Adopter	Southern
College	29 MW	Adopter	Southern
Community college district	1.3 MW	Adopter	Northern
Community college district	1 MW	Non-adopter	Southern
Community college district	1.45 MW	Adopter	Southern
Computer networking equipment	Up to 5 MW	Non-adopter	Northern
Computer software company	20 MW	Non-adopter	Northern
Government facilities	Up to 5 MW	Non-adopter	Southern
Government facilities	1.8 MW	Adopter	Northern
Government facility	1.5 MW	Adopter	Southern
Grocery store	280 kW	Adopter	Northern
Material manufacturing	600 kW	Non-adopter	Northern
Material manufacturing	1.5 MW	Adopter	Northern
Medical center	6 MW	Non-adopter	Northern
Pharmaceutical research	2.2 MW	Adopter	Southern
Printing company	4.2 MW	Non-adopter	Northern
Prison	1 MW	Non-adopter	Northern
Semiconductor manufacturing	3 MW	Non-adopter	Northern
Ski resort	Up to 2 MW	Non-adopter	Southern
Water district	2.5 MW	Non-adopter	Southern

For the interviews with CHP adopters, we focused on the drivers for adding CHP to the facility, concerns about the project that they had at the time, and their feedback on a variety of policy initiatives for encouraging adoption of CHP. The interviews with non-adopters focused on the obstacles they encountered in trying to add CHP, the barriers that ultimately prevented them from adding CHP, and their feedback on the effect of potential policy initiatives to promote CHP.

The in-depth interviews ranged from approximately 30 minutes to more than 1 hour and followed a topic guide developed by Primen in consultation with the project team. The final version of the interview guide can be found in **Appendix I.**

To encourage candid conversations, respondents were told that even though we might quote their remarks, we would not attribute their remarks by name or by organization, or otherwise make it possible to learn the source of the remarks. The interviews were taped (with the respondents' permission) to facilitate analysis.

Direct quotes, in some cases abbreviated or paraphrased for clarity or to preserve respondents' anonymity, appear as indented and italicized text,

> *like this.*

In addition to the energy user interviews, we spoke with three project developers to get their perspectives on the drivers and barriers to expanding CHP in California. These project developers were not willing to provide contact names for their customers or prospective customers, but were happy to provide their own viewpoints on energy user drivers and barriers, as well as feedback on how policy initiatives would affect their clients' abilities to go forward with CHP.

Findings from Prior Market Research

Recent primary market research (2003) found that 13% of establishments nationwide in the 100 kW to 10 MW demand range were considered prospects for baseload applications of onsite power generation.[16] Of these prospects, 2%, or 12,000 business establishments were actively evaluating their project options.

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[16] Nicholas Lenssen, Brian Byrnes, and Shawn McNulty, "Converting Distributed Energy Prospects into Customers," Primen Distributed Energy Market Study 2003, DE-MS-01-03, Boulder, Colorado, December 2003. The Primen study considers **prospects** as energy users that say they are more than 50% likely to acquire baseload distributed energy (DE) within the next two years. Primen then breaks down the prospects into strong prospects and soft prospects. **Strong prospects** are those that say that they area likely to acquire DE within the next two years and they are actively evaluating their options. **Soft prospects** on the other hand also say that they are more than 50% likely to acquire DE within the next two years, but have not begun to actively investigate their options.

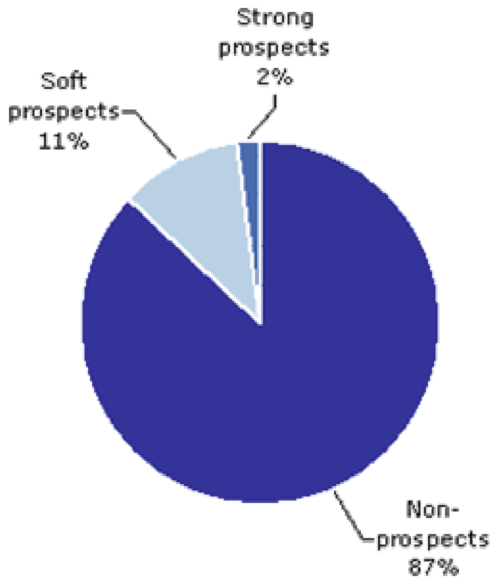


Figure 3-1
Nationwide Market Interest in Onsite Generation

According to the 2003 study, the top three drivers for DE nationwide were:

- energy cost savings
- improved power reliability
- greater predictability of future energy prices

Energy users had several concerns about onsite generation in 2003. Most important was the expected payback period for projects, as internal rate-of-returns hurdles on projects prevented most energy users from considering adding an onsite generation project to their facility. Respondents, however, also raised concerns about natural gas prices and volatility, environmental permitting for projects, utility interconnection requirements, maintenance issues, and warranties in the event of equipment failure.

In general, the findings supported the notion that although economics are key to DE decisions, economics alone won't sell onsite generation projects.

Interest in baseload onsite generation has fluctuated over the past few years. During the Western power crisis of 2001, more than 20% of energy users in the 300 kW to 5 MW demand size range were prospects for onsite generation, though in 2002, the number dipped to less than 15%. (See Figure 3-2). In 2003, interest in baseload onsite generation began to rebound; however rising natural gas prices in late 2003 and into 2004 likely stopped or even reversed this trend.

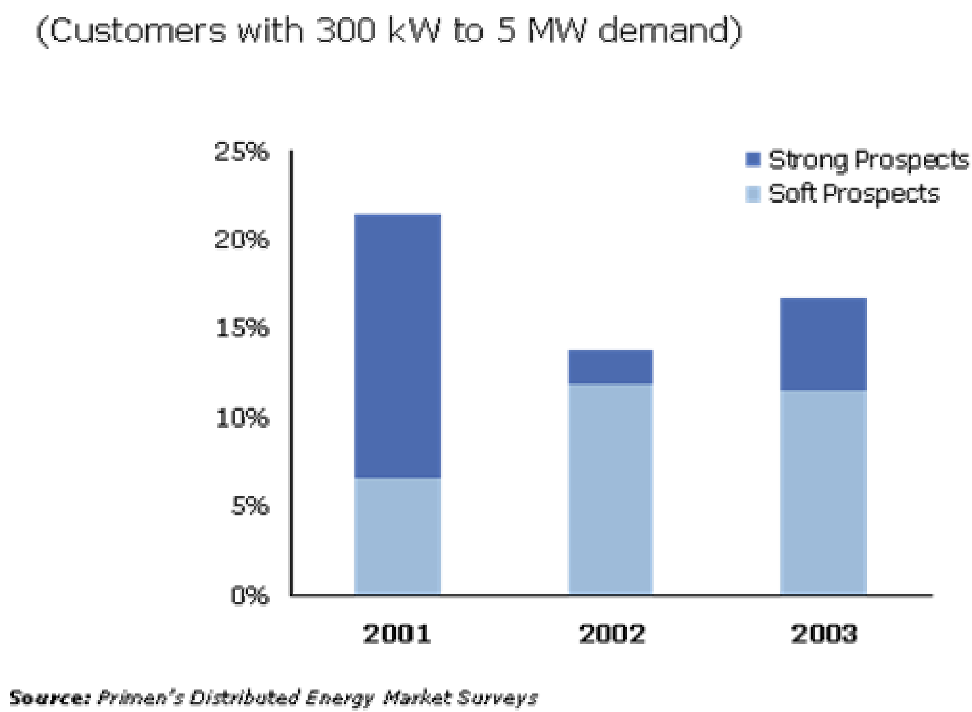


Figure 3-2
Nationwide Market Interest in Onsite Generation, 2001-2003

Drivers of Interest

The primary drivers for onsite generation include the bottom line and reliability. When asked about the drivers for onsite generation, three reasons were mentioned most. The most commonly cited driver for onsite generation nationwide was to save money on energy, followed by more reliable power. The third was a desire for greater predictability of energy prices. These were the top drivers among strong prospects, as well as soft prospects. (See Figure 3-3)

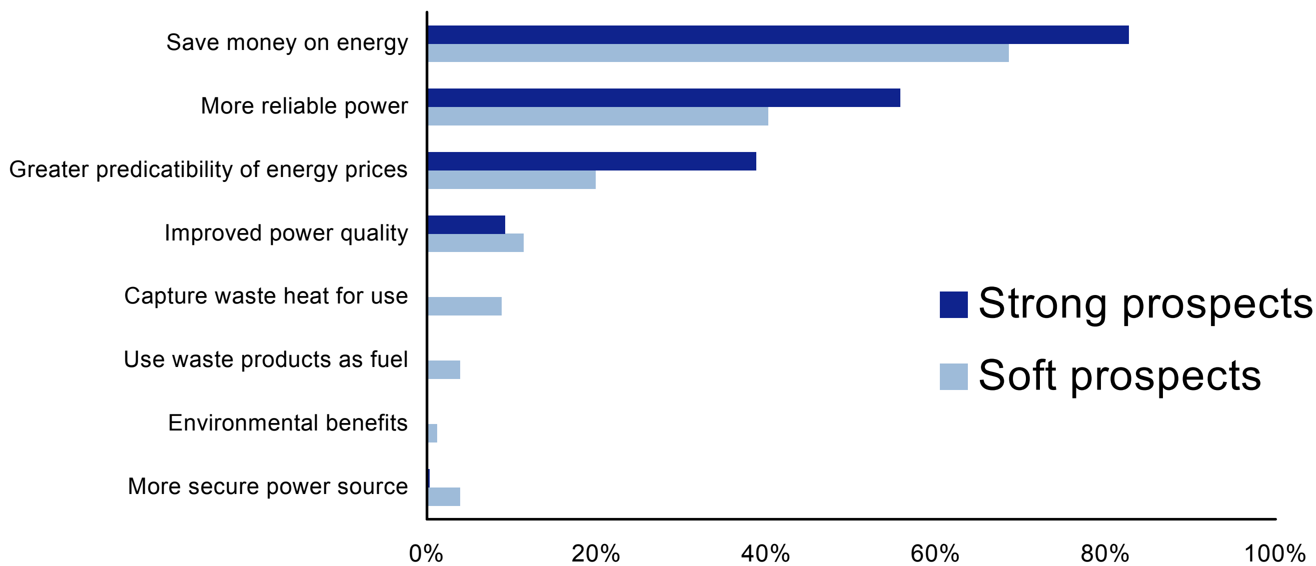


Figure 3-3
Nationwide Drivers for Onsite Generation: Bottom line and reliability

Payback Requirements

While the drive for onsite generation at a facility may exist to save money or increase reliability, it inevitably must meet a certain payback in order for a business to pursue onsite generation further. However, companies vary in their risk tolerance and therefore an acceptable payback period varies from as little as six months for some companies to 11 years or longer for others. As shown in Figure 3-4, less than half of the energy users found a two year payback period acceptable.

The survey sample included enough sample points in California to meaningfully compare California with the national data. Figure 3-4 shows the percent of establishments in California and nationwide that would find the various payback periods acceptable for onsite generation. Note that California energy users demonstrated the same payback requirements as energy users nationwide.

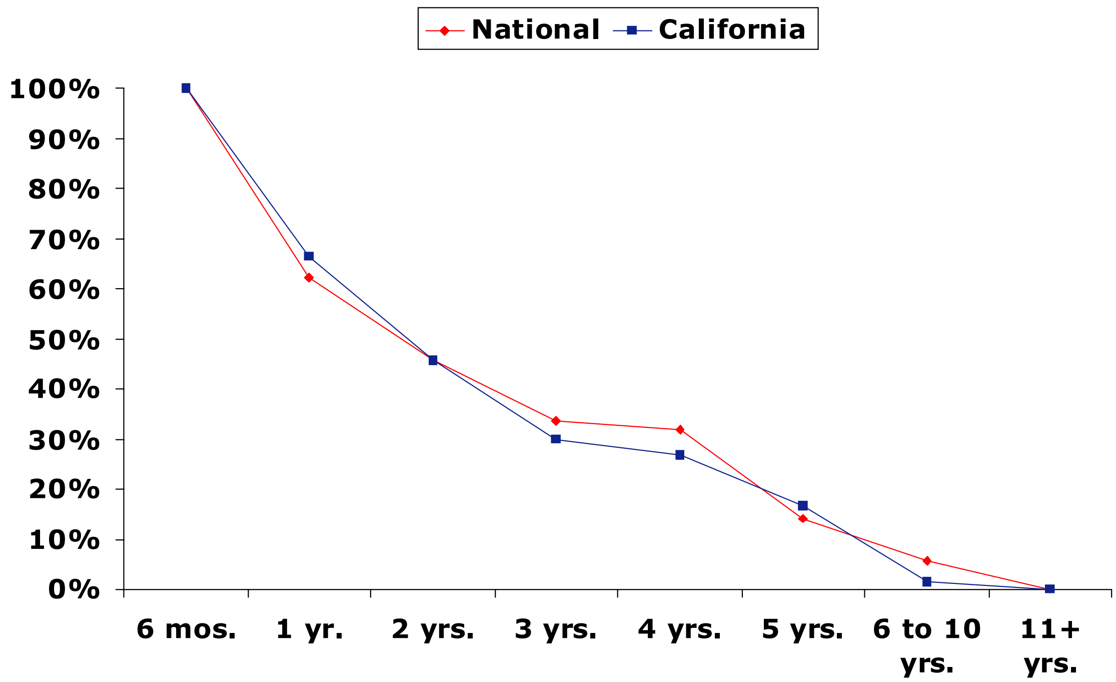
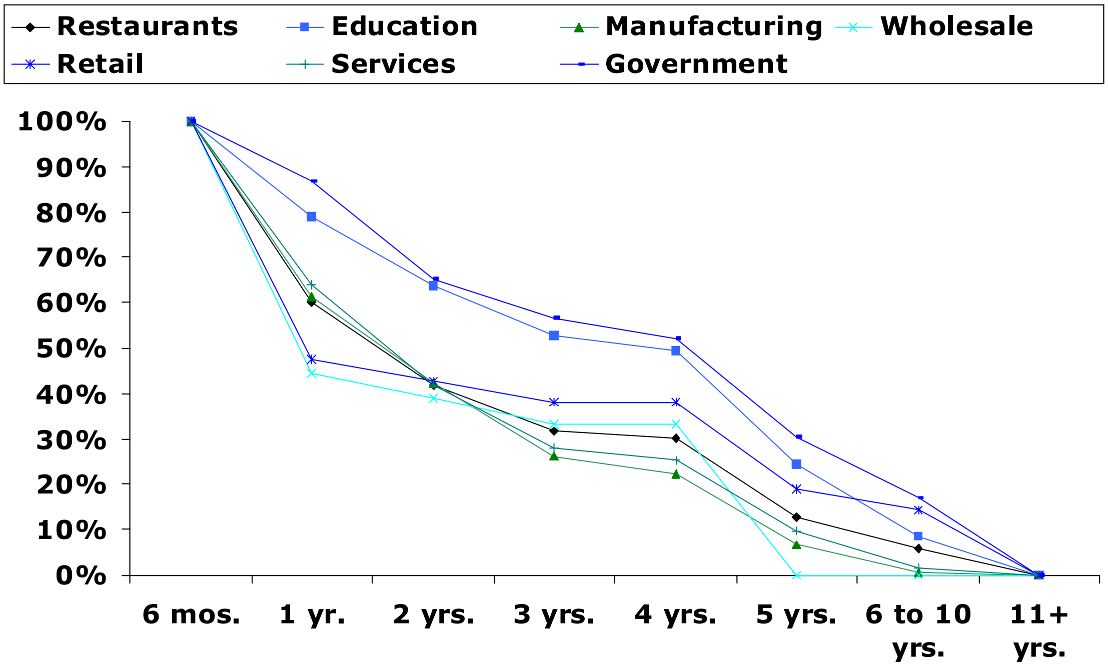


Figure 3-4
Payback Acceptance in California and Nationwide

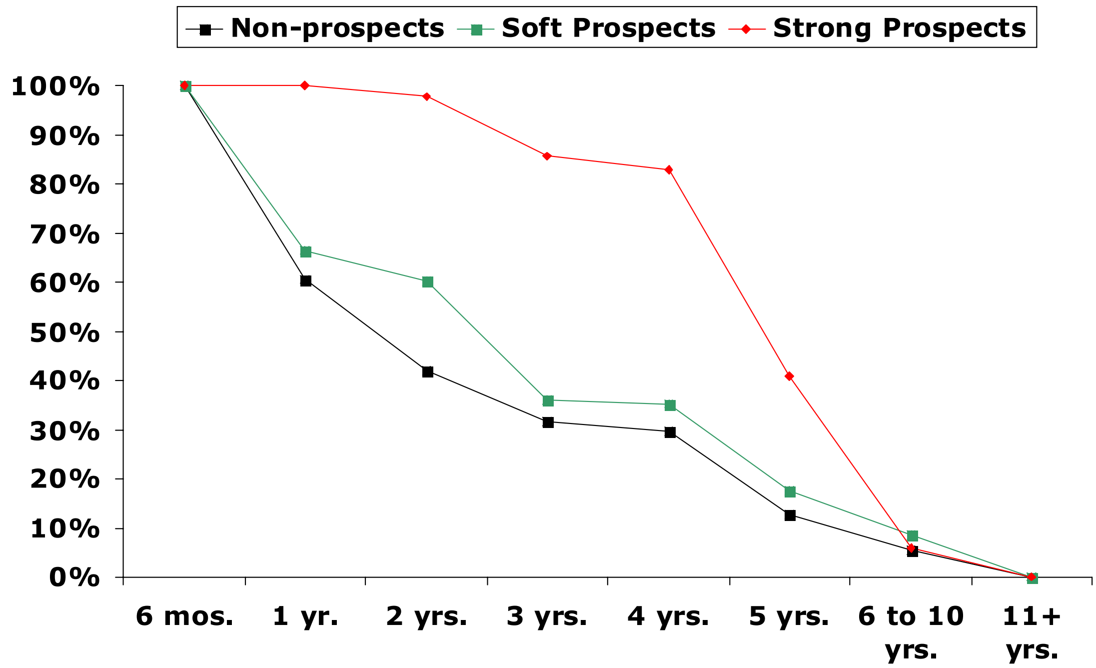
Government and education establishments were found to be more willing to accept a longer payback period. (See Figure 3-5) That is likely due to the fact that capital expenditures at these types of establishments are typically funded through bond programs, which can spread the cost out over longer stretch of time. Wholesale and retail establishments in the private sector typically have higher rate-of-return investment criteria, making the economics for an onsite generation project more tenuous. There was little difference in payback acceptance by facility size.



Source: *Primen's 2003 Distributed Energy Market Survey*

Figure 3-5
Payback Acceptance by Business Type

Strong prospects, those that said they were actively evaluating onsite generation options and were more than 50% likely to go forward with a project in the next two years, were willing to accept longer paybacks – up to a point. Almost 90% of strong prospects would consider a payback of 4 years, but acceptance begins to drop rapidly once paybacks reach 5 years. (See Figure 3-6.)



Source: *Primen's 2003 Distributed Energy Market Survey*

Figure 3-6
Payback Acceptance by Prospect Type

Barriers to Adoption

Although cost savings and enhanced reliability are the fundamental drivers for energy users to adopt onsite generation, other criteria need to be addressed to really sell an onsite generation project to an energy user. These issues, which can become barriers if not addressed, include the following:

- The company's financial position and/or the state of the economy
- Availability of financing from the vendor/project developer
- Specific warranties or guarantees provided
- Service agreement included/offered
- Addressing environmental or permitting issues
- Electric service provider's flexibility, or lack thereof, in resolving tariff and interconnection issues
- Fuel prices, particularly for natural gas
- Ability to cogenerate heat, steam, or chilled water along with power

Based on 100 in-depth interviews with end-users who were either currently actively considering or had completed an onsite generation project in the prior 5 years, respondents were asked which factors had or currently were having a high impact on the onsite generation project going forward. The issues with a high impact were specific warranties or guarantees provided, environmental issues, fuel prices, and service agreements. (See Figure 3-7.)

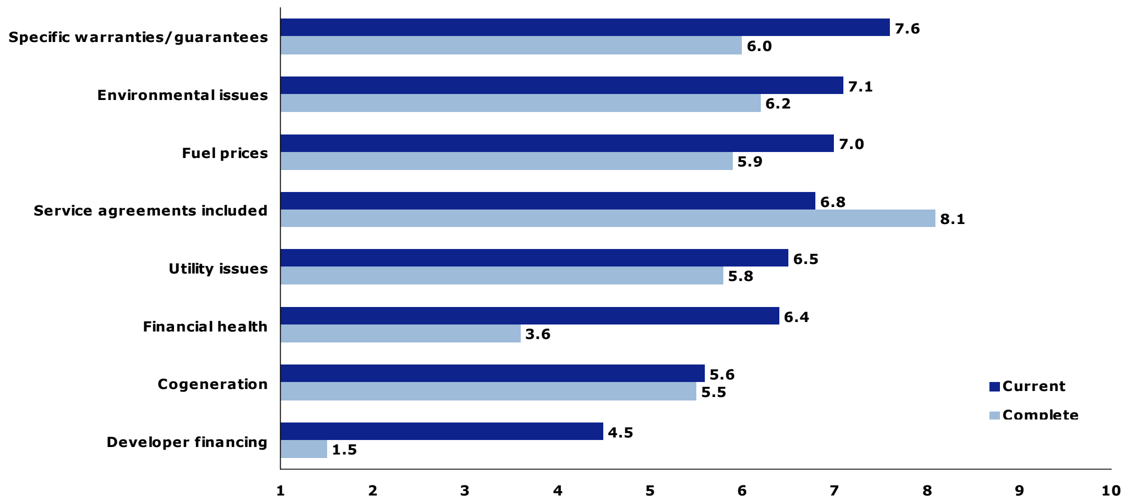


Figure 3-7
Key Issues Influencing Onsite Generation Sales in North America

Implications for the California Market

Sales of onsite generation and CHP are not easy, and California policymakers face an uphill road to increased CHP capacity in the state. Less than half of the energy users say a two-year payback is acceptable. Beyond paybacks, other issues can easily derail the CHP project development pathway. In addition, market and policy gyrations of the past 10 years have led to the adoption of less CHP than previously anticipated.

The users who have the lowest economic threshold are government and education segments. In contrast, the private sector is less willing to accept longer paybacks. Therefore understanding the key policies that can "tip" a prospect to become a customer is a crucial step. The in-depth interviews aim to find those drivers/incentives that could increase positive buying decisions by energy users, and point the way for policymakers to take action.

Interviews with California End-Users and Developers

The drivers for adding CHP in California are energy cost savings and improved power reliability. This finding from the in-depth interviews with California end-users is consistent with the findings from the prior national studies. In the 2003 national study, the top drivers included energy cost savings, improved power reliability, and predictable energy prices.

California interview respondents mentioned several barriers to adopting CHP, with most related to simple economics: the payback period for investing in CHP is simply too long. Respondents mentioned several factors that contribute to the length of the payback period, including

- capital cost of the equipment
- cost of natural gas
- charges related to grid interconnection

A smaller group of respondents also said that despite the electricity and natural gas price spikes of recent years, energy costs and CHP still have not caught the attention of "upper management" who has the authority to allocate capital resources to develop CHP projects.

Among the policy initiatives that respondents found most attractive were those that improved the overall economics of CHP. More specifically, respondents preferred net metering and expanding the Self Generation Incentive Program (SGIP) to projects with capacities of up to 20 MW and increasing the incentive up from the current 1 MW cap.

The project developers that we spoke with concurred with the energy users interviewed by identifying the drivers for CHP as energy cost savings and increased power reliability. They, too, have encountered users saying that the payback on a CHP project is too long for their customers. In particular their customers say they do not have the capital on hand to pay for the system.

Given the economic focus of their customers, it is not surprising that project developers chose net metering and measures that would lower the price of natural gas as their preferred policy measures. Other policy options favored by developers include the establishment of a third party to oversee standardization around interconnection and measures to incent utilities to support CHP. One developer also cited California's approach to incenting energy efficiency as a model for increasing utility interest in CHP.

Finally, project developers would also like to see someone with governmental authority who would function as an ombudsman and facilitator for CHP projects. This individual could serve several functions including assisting facilities and project developers in navigating the permitting process, particularly with respect to the California Environmental Quality Act (CEQA), and providing local governments with references for similar projects (so they didn't have to rely on/trust ones provided by the project developer).

Drivers of Interest in CHP/CCHP

Energy cost savings and improved power reliability are the primary drivers for adding CHP in California. One of these, if not both, was mentioned in practically every interview. As electricity prices in California skyrocketed in 2000 and 2001, facilities began to look at CHP to provide their own power for a lower cost of energy.

> *The cost of energy obviously was the biggest driver.*
> *—- Printing company, a 4.2 MW non- adopter in Northern CA*

> *… the more cogen that we install the less electricity we are going to consume and our utility bill is going to go down.*
> *– Community college district, a 1 MW non-adopter in Southern CA*

Likewise, when California began experiencing rolling blackouts in 2001, companies turned to CHP to provide a consistent source of power to get them through the downtime caused by the blackouts.

> *Everybody collaborating at that time was looking at reliability issues and how to get away from the power outages and blackouts. In the back of everybody's mind was 'Why can't we generate our own power?'*
> *– Computer software company, a 20 MW non-adopter in Northern CA*

> *The reliability – being a little bit independent of the utility – so that if CA went through another power crisis, we would be in a position where we could support ourselves.*
> *–Printing company, a 4.2 MW non-adopter in Northern CA*

These results are consistent with the findings from the national studies. However, in the national studies, a third driver was also mentioned frequently – predictable energy prices. Although most of the California respondents expressed frustration with increasing energy prices when probed, they did not mention price stability as a driver for adding CHP to their facility. Still, one California user did perceive benefits in buying gas on a forward-price basis.

> *I'd personally thought about [buying gas on a forward-price basis] since gas prices have been all over the map lately. That would be good, although you'd require additional staffing. I think it would be helpful because you could plan it and budget accordingly.*
>
> *- Hospital, a 6 MW non-adopter in Northern CA*

Barriers to Adoption

The respondents mentioned several barriers to adding CHP to their facilities, but most were related to the underlying economics and payback for CHP projects. Although several factors contribute to the length of the payback period, respondents specifically mentioned the capital cost of the equipment, the cost of natural gas, and the interconnection charges.

> *While we are still saving money, the simple payback increased from about 7 years to closer to 12 to 15 years! We based our calculation of projected future savings primarily on the price of natural gas, and we guessed wrong! We thought natural gas prices would accelerate at a slower pace than electrical rates, but that has certainly not been the case.*
>
> *- Community college district, a 1.5 MW adopter in Southern CA*

Some respondents said that energy costs and CHP technology have not caught the attention of "upper management" who has the authority to allocate capital resources to develop CHP systems. For these facilities, until the CFO, president, or board of trustees recognizes the potential for energy cost savings, projects won't go forward.

> *The main reason that we haven't added [CHP] is because we haven't got the financing or the capital approved by the board of supervisors. Or at least we haven't gotten their interest to the point where they think that it is a worthwhile use of our capital funds. All of the studies show that it* **is** *worthwhile and the paybacks are very short 2–4 years, so it certainly is doable.*
>
> \- *Government facilities, up to 5 MW non-adopter in Southern CA*

> *Unfortunately, it's just not at a point where anybody is willing to make it a priority. When the price of electricity went out of sight I was able to show the Board of Supervisors that it was economically feasible. But, it just hasn't gotten up to a priority level, even though they have decided that they do want to fund.*
>
> \- *Medical center, a 6 MW non-adopter in Northern CA*

Reactions to Proposed Policy Initiatives

In general, respondents preferred those policy initiatives that would improve the overall project economics. When asked to what **one** policy option the state should adopt to encourage CHP, respondents most commonly mentioned either allowing end-users to sell excess power back to the grid or modifying the SGIP to apply to projects of up to 20 MW and increasing the incentive up from the current 1 MW cap.

The most popular choice among respondents was allowing facilities to sell excess power back to the grid. Although selling excess power would help the overall project economics, some respondents remained concerned about the complexity and cost of working with the utility to accomplish this goal. Furthermore, most respondents repeatedly confused this ability to sell power into the wholesale market with net metering, commonly using the latter term.

> *Net metering is something we discussed when we originally did the project, but because of the complexities and bureaucracy involved we decided not to go down that path. I guess if the red tape could be cleaned up. It would certainly be something that we'd be interested in.*
>
> *– Printing company, a 4.2 MW non-adopter in Northern CA*

I would LOVE net metering. Currently I am operating my equipment at less than optimal. If I could take advantage of net metering, I could efficiently operate my equipment, which is good for me and good for the environment.

– University, a 14.3 MW adopter in Southern CA

Modifying the SGIP (both allowing projects up to 20 MW to apply to the program and allowing more than the first MW to be covered by the incentive) was the other commonly requested policy change.

Any financial incentive like that would have helped if I could have brought it into the project. For me, it would be nice if it were increased to 6 MW because that is the size of my project. But in general, I would think increasing it to 10 MW would be good for encouraging future projects.

- County hospital, a 6 MW non-adopter in Northern CA

Any sort of increase would have been a positive factor. A lot of our colleges in the district are in the 4-6 MW kind of load. So moving it from 1MW to 4MW for a college district would be really great. I think most colleges could do really well with a baseload of 4 MW.

– Community college district, a 1 MW non-adopter in Southern CA

Respondents were also positive about several of the other policy options presented that could improve the overall economics, including:.

Credit on monthly bill that equals the wholesale price of the power produced onsite

This approach would effectively pass the utility's wholesale power purchase savings onto the end-use customer. Several respondents liked this option because it would help the project economics. However, some respondents were skeptical of how this policy would work.

That is interesting, but boy, that sounds like another layer of regulation. It starts to be too complicated.

- Ski resort, an up to 2 MW non-adopter in Southern CA

Elimination of interconnection fees

For several adopters, their interconnection fees ended up being a significant amount, impacting the payback period. These users suggested the elimination of interconnection fees as a method to improve economics and reducing uncertainty. Non-adopters, too, perceived interconnection fees as a barrier that should be eliminated.

Absolutely! It seems to me, I can't remember all the details right now, but it seems to me the exit fees were going to be pretty significant. And obviously if we can avoid it we would certainly like to do so.

- Printing company, a 4.2 MW non-adopter in Northern CA

Purchase natural gas on a forward price basis

By purchasing natural gas on a forward price basis, facilities would be able to avoid fuel price volatility. Although most respondents were interested in such a policy, respondents did not think that the current natural gas market, with prices so high, made it an attractive offer.

Well, that was always our intent. Unfortunately we didn't secure any long-term contracts to allow us to do that. At this point we're just paying market price until prices come down a little bit and we can get into a longer-term agreement.

- Printing company, a 4.2 MW non-adopter in Northern CA

Purchase natural gas at a lower rate than they currently can

The option for CHP owners to purchase natural gas at a lower rate than they currently can was well received by the majority of respondents. In some cases, gas prices started out low enough to make the project economics work, but as they increased the project was no longer economically feasible.

That would definitely help. When I first started looking at this, I could make the payback pan out with gas prices at $4 - $4.50 per Btu. So if the lower rate can get me down to that level, I can proceed with my project. Natural gas was an important part of the consideration.

- Semiconductor manufacturer, a 3 MW non-adopter in Southern CA

Typically, respondents said that the rate only had to be marginally lower than current rates in order for it to affect the ability to go forward with a CHP project.

As for rates, I would think even a 5% decrease from the current rate would be wonderful. That would be a big deal. A very big deal.

- Community college district, a 1 MW non-adopter in Southern CA

Elimination of exit fees

The elimination of exit fees for CHP owners would have a positive impact on the overall economics for several facilities. Most respondents liked this option, though they did not feel that it would have had as much impact on their project as some of the other options mentioned, such as the elimination of interconnection costs or the ability to sell power back to the grid.

I definitely think they should get rid of the exit fees. I mean that is like the post office charging a fee for every email sent. It just doesn't make sense.

- *Government facility, a 1.5 MW adopter in Southern CA*

Yes, that would help, but I'd still prefer to get rid of the interconnection costs.

- Computer software company, a 20 MW non-adopter

A state tax credit for CHP owners

Several respondents liked the policy option of providing a state tax credit for CHP owners. It resonated due to its simplicity and ease of understanding.

That would probably be pretty popular. I don't know what the amount would need to be, but I know that tax credits are pretty popular with our company.

- *Material manufacturing, a 600 kW non-adopter in Northern CA*

Several of the respondents that we spoke with from government facilities pointed out that they do not pay state taxes; therefore, this option would need to have a market transfer mechanism included to allow government organizations to earn a market value from the credit. This would be consistent with prior tax incentives, such as the Federal Production Tax Credit, that have allowed government agencies to transfer the credits to non-government entities.

Other Policy Options

California energy users were asked about other policy options that could assist in the project planning phase for CHP, including

- Vendor certification lists from the local utility or the state
- Availability of state financing
- Availability of low cost financing
- A faster, more streamlined permitting process

Most respondents did not see much value in these initiatives. While each was considered "nice to have," the respondents did not think that these changes would have a significant impact on adding more CHP in California.

Those are all nice, but anything that is going to help our payback calculation is what we'd be in favor of.

- Printing company, a 4.2 MW non-adopter in Northern CA

Vendor certification lists

Although finding a vendor was not a problem for the overwhelming majority of respondents, most thought that a vendor certification list – whether provided by the local utility or the state -- would be helpful. Key benefits of such lists include having a third party evaluation of vendors and technologies and being able to identify vendors with a local presence or who have successfully completed projects while working with the local utility.

> *Vendors are crawling out of the woodwork because of the incentive money, but it would be nice to have a way to weed through them initially….to find out if they are good people to work with or not.*
>
> \- *Brewery, a 1 MW adopter in Northern CA*

> *Yes, especially if they have information on their experience and some sample projects that they have done that you can examine; listing their size – number of employees, experience, success of the technology, all those things.*
>
> \- *Government buildings, an up to 5MW non-adopter in Southern CA*

The availability of CA state financing

For most respondents, the offer of California state financing of CHP projects was not particularly useful, as obtaining financing was not a problem for most respondents. However, for those respondents that thought they would have a problem obtaining financing, CA state financing would be helpful – though a few were skeptical about the "strings-attached."

> *It definitely would [be helpful]. Well my hesitance is the requirements around it. I looked at it previously and you were limited because of the bonding or the requirements around it. But I would definitely do it just to get the money.*
>
> \- *Medical center, a 6 MW non-adopter in Northern CA*

Availability of low cost financing

Although finding financing for projects was not an issue for most respondents, low cost financing generated more interest than the CA state financing option. Respondents are only looking for a minor decrease in the cost of financing – generally a relative decrease of 5-10% below today's rates.

> *Yes, that would help. It doesn't really take much – even a 5% decrease would help some of our future projects.*
>
> \- *Grocery store, a 280 kW adopter in Northern CA*

A faster, more streamlined permitting process

Permitting, particularly air emission permitting, was mentioned as a problem for a few respondents. Although they expressed frustration with the permit process respondents agreed that a faster, more streamlined permitting process would not have made a difference in whether their project went forward or not.

> *Yeah, there was a little bit of an issue there [with permitting issues]. I do have a good relationship with our local city so they pushed [the project] through fairly quickly for us, but the air district permitting can be a little bit of a boon-doggle sometimes. But, no it wouldn't have made a difference. We were still going to move forward with it.*
>
> *- Brewery, a 1 MW adopter in Northern CA*

> *There wasn't a lot of guidance being provided [on Rule 21]. Initially it was along the lines of "Okay, here's the Rule 21 document. You read it. You figure it out and submit something to us and we'll tell you if it meets it or not." . . . it would have been nice to have a sort of checklist saying "okay here's all the things you need to go through to get to the end of the Rule 21 certification." So for us, it was definitely on the learning curve, but that didn't hold us back.*
>
> *- Printing company, a 4.2MW non-adopter in Northern CA*

Project Developers Favor Economically Supportive Policy Measures

The project developers we interviewed also supported allowing CHP owners to sell power to the grid and expanding/increasing the SGIP as the most effective policies for encouraging CHP in California. In their view, economics are truly the bottom line for most adopters of CHP.

But the project developers suggested other options for the State to consider, specifically adopting measures that would incent the local utility to support rather than oppose CHP development. CHP, in the eyes of project developers, competes with the local utility. Without incentives in place to encourage the utility to cooperate and help projects move along in an efficient manner, perceived utility foot-dragging results. One project developer thinks that the only way to prevent the utility from dragging its feet is to provide incentives to the utility in a similar fashion as California's demand-side management (DSM) programs were encouraged, where utilities could earn a higher rate of return or other incentive for helping develop (but not own) CHP projects.

They need to give the utilities incentives to help out like they did back with the efficiency programs. Right now the utility is polite, but there is no reason for them to make adding CHP a priority. The utility dragging its feet can cost projects significantly. The utility is the one that knows its grid and could apply CHP efficiently. As it is right now, it's anyone's guess as to where CHP is needed.

Project developer

4
EVALUATION OF POLICY OPTIONS TO ENCOURAGE CHP MARKET PENETRATION

Introduction

In an effort to understand the implications of potential policy instruments the Integrated Energy Policy Report (IEPR) could recommend to encourage CHP market growth, E3 conducted an analysis of several policy portfolios that could be implemented by the State. This research contributes to development of approaches for incentives and other options to realize the CHP opportunity in the State of California and was completed in conjunction with the CHP penetration analysis (Chapter 2) and the market research on the California CHP market (Chapter 3) and will provide insights for the analysis and subsequent recommendations of future research needs (Chapter 5). The results presented here aim to clearly identify benefit and cost impacts to stakeholders including CHP / CCHP owners and users, electric utilities and their customers, and society for use in the 2005 Integrated Energy Policy Report development process.

In evaluating the numerous potential policy options available for encouraging CHP resources, the following characteristics were considered desirable for successful policy options.

- Meet stakeholder goals; including for example,
  - Higher efficiency use of the State's energy resources
  - Positive environmental impact
  - Low impact on utility rates and minimal cost-shifting
- Promote best projects (as defined by stakeholders goals)
- Be relatively easy to implement
- Require low incentive payments
- Have a realistic exit strategy

Since no single policy can embody all of the above characteristics, our team developed several portfolios of policies with different fundamental themes, and then evaluated each portfolio relative to the stakeholder goals both qualitatively and quantitatively. The intent of the different portfolios was to cover the spectrum of policy choices and stakeholder perspectives. The nine portfolios included in our analysis are:

1. Base Case; no change in existing policy
2. No Incentives; removal of all existing incentives
3. Moderate Market Access; improve access to wholesale energy markets

4. Aggressive Market Access; improve access to wholesale energy markets, and provide mechanism to include CHP for Generation and T&D capacity
5. Increasing Incentives; expand SGIP and develop a production tax credit
6. Streamlining CHP Installations; set of policies to improve customer outreach, simplify permits and interconnection
7. Increased R&D Funding; keep existing policy and focus on technology development
8. Increased R&D Funding with Aggressive Market Access; combination of two policies
9. Portfolio Standards; set a target penetration level and adjust incentives, or conduct bidding for payments, until the target is reached (the portfolio standard can be combined with the other policy portfolios)

Our team performed two quantitative analyses of the policy portfolios. One analysis evaluated the costs and benefits of an individual CHP installation under a policy portfolio, and summarized the levelized costs and benefits from the CHP owner, utility, and societal perspectives. The results of this analysis were computed for portfolios 1 through 5 and are shown in Step 4 later in this chapter. This analysis is useful to understand the trade-offs between stakeholders costs and benefits (increased incentive to one is a cost to another), and evaluate the potential for 'win-win' outcomes where all stakeholders are no worse off after implementing the policy.

The second analysis evaluated the penetration of CHP systems of different types under the policy portfolios 1 through 8. This analysis is useful to estimate the installed capacity of CHP in aggregate and by market segment and the potential for different technologies. The penetration analysis was documented and discussed in Chapter 2. The total benefits and costs for California were then summarized for each stakeholder and portfolio based on the penetration estimates. Our team did not quantitatively address portfolio 9 within either the individual installation cost-benefit analysis, or the total penetration analysis.

These analyses and a qualitative assessment of non-quantifiable stakeholder goals, form the basis of our conclusions.

Summary of results & implications

Several conclusions become apparent when evaluating the policy scenario results along with the penetration results from Chapter 2. Figure 4-1 illustrates the results of the both the stakeholder policy analysis and the associated penetration impacts for each scenario. In this figure, the green bar above the line represents the CHP owner's savings on a net-present-value (NPV) basis for new installations through 2020. The purple bar below the line indicates the utility/ratepayer loss on a NPV basis for new installations through 2020 which is the impact of increased CHP penetration on non-participants. The societal benefits of each scenario are shown as a blue-triangle. Finally, the cumulative CHP penetration is indicated as an orange line with squares.

A primary distinguishing policy difference between scenarios is a policy that facilitates the export of energy from CHP onto the transmission and distribution system at wholesale electricity prices. The three scenarios to the right of the dashed line allow for wholesale energy export and yield the highest penetration because the installations that benefit from export tend to be very large as described in Chapter 2. These cases also result in the highest societal benefits because large CHP facilities have higher efficiency and reduced CO_2 emissions than central station plants as was shown in **Figure 4-1**.

Another key finding is that all policy options, including the base case, result in losses in electric utility revenue that are greater than the corresponding savings. While we discuss policies that can mitigate impacts to utility shareholders, this loss would necessarily need to be made up with either rate increases or increased utility value from CHP installations, or both. We see that the market access portfolios that have policies to encourage participation in energy and capacity markets, as well as T&D capacity, do mitigate the utility losses somewhat.

Another important result is that in the scenario with increased incentives, the majority of the societal benefits from CHP installations is not retained by society but rather transferred to the CHP owner through a production tax credit.

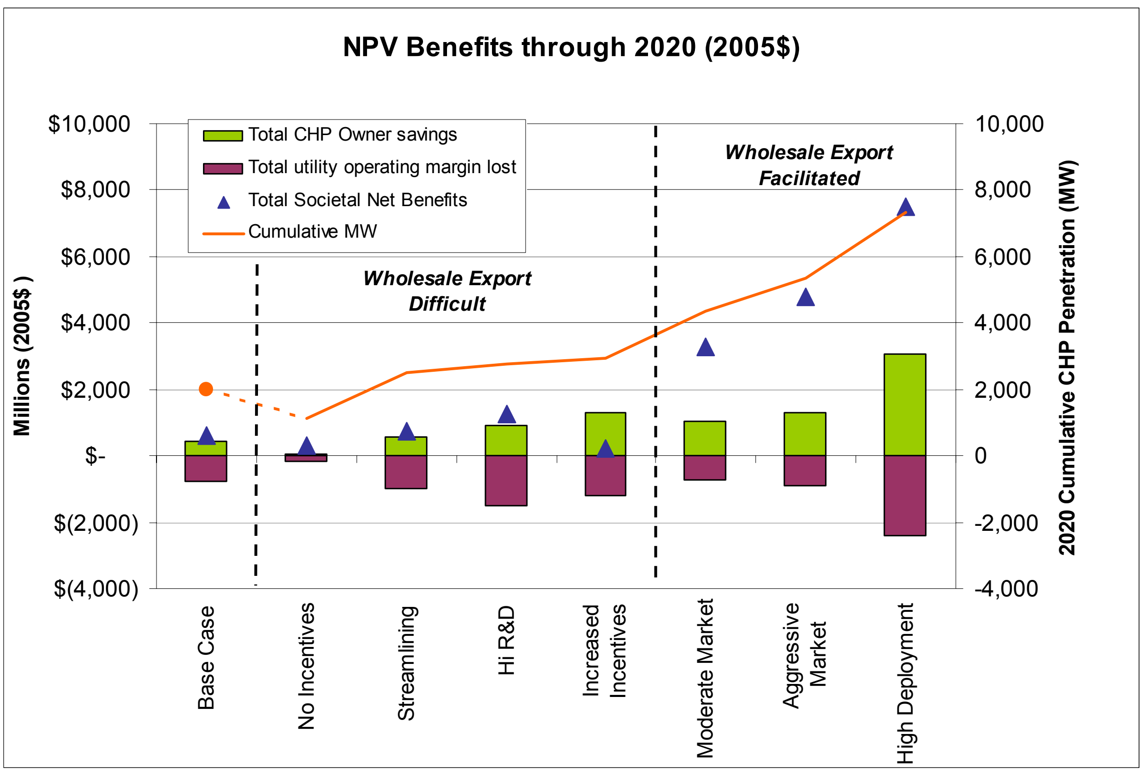


Figure 4-1
Stakeholder Net Benefit Results of Policy Scenarios ($2005) and CHP Penetration Levels (MW)in 2020

Table 4-1 provides the numerical results as graphed in Figure 4-1. The three center columns show the values in millions of dollars (2005$) and represent the net benefits accrued through 2020 on a net present value basis. The right-hand column shows the cumulative MW column indicates the penetration levels associated with each policy portfolio.

Table 4-1
Net Benefit Values by Stakeholder and Cumulative CHP Penetration for each Policy Portfolio

Portfolio	NPV through 2020 (in millions - 2005$) Total CHP Owner savings	Total utility operating margin lost	Total Societal Net Benefits	Cumulative MW
No Incentives	$ 54	$ (183)	$ 306	1,141
Base Case	$ 451	$ (759)	$ 620	1,966
Streamlining	$ 571	$ (1,005)	$ 734	2,489
Hi R&D	$ 899	$ (1,485)	$ 1,255	2,764
Increased Incentives	$ 1,285	$ (1,183)	$ 201	2,942
Moderate Market	$ 1,049	$ (720)	$ 3,286	4,377
Aggressive Market	$ 1,317	$ (884)	$ 4,791	5,348
High Deployment	$ 3,067	$ (2,387)	$ 7,516	7,340

CHP Policy Analysis

Our team conducted the CHP policy analysis in following the four steps. A discussion of the impacts of this analysis including increased penetration, cost of incentives to the State, and impact on non-participants (utility customers and shareholders) is provided in the subsequent sections. Further supporting information about the policies evaluated, assumptions used, and input values included in our analysis are provided in Appendices H and I.

Step 1: Determine key issues slowing rate of CHP installations

Step 2: Identify master list of policy options

Step 3: Develop CHP policy portfolios and qualitatively evaluate key stakeholder issues with each

Step 4: Perform benefit-cost analysis from customer, utility, and society perspectives of individual CHP applications of different types

Step 1: Determine key issues slowing rate of CHP installations

Prior to initiating the stakeholder policy analysis, our team determined the key issues that potential and current CHP customers have specified as major barriers to CHP installations. The primary sources for determining which issues were most prominent included:

- Market assessment data – 2003 national survey conducted by Primen (EPRI Solutions, Inc) and feedback from interview process conducted concurrently with this policy analysis[17].

[17] Primen's 2003 Distributed Energy Market Survey

- Energy Commission input – feedback from potential CHP adopters and industry groups.
- Industry experience of consultant team - E3, along with EPRI, EEA, and Primen (EPRI Solutions, Inc.) has extensive experience in the electricity industry.

Relying on the above sources, our team was able to narrow down the key issues that have contributed to the lack of widespread penetration of CHP installations in California. We recognize that throughout the CHP markets, there are likely to be project-specific issues that would prevent or stall a CHP installation but for the purposes of this analysis, we have focused on the primary drivers and barriers in the marketplace for CHP. The key issues our team focused on for the policy analysis are shown in

Table 4-2
Key Issues for CHP Stakeholders

Key Issues for CHP Stakeholders	
Customer	**Utility**
High technology capital cost	Electric utility net losses
Investment risk/market uncertainty	Not coordinated with resource adequacy requirements
Operating costs	Not a part of utility goals or targets such as CA-RP
Hassle factor/Not core business	

Secondary issues, examples of which are shown in Table 4-3 while considered very important, were not reported as the main obstacles of CHP installations. However, those policies that can mitigate these and other secondary issues, would be considered more successful in our analysis.

Table 4-3
Examples of secondary Issues for CHP Stakeholders

Secondary Issues for CHP Stakeholders	
Customer	**Utility**
Interconnection costs	Lack of technology experience
Siting & permitting process	Low value
Lack of technical knowledge	High hassle factor

Step 2: Identify master list of policy options

Using these key stakeholder issues as a guide, our team identified over 30 different policy options in 9 implementation categories as shown in Table 4-4. Each policy acts to address or mitigate one or more of the key issues described previously. For example, a policy program that involves targeted marketing to potential CHP customers acts to both promote high-value CHP installations as well as educate potential future owners. Alternatively, a rate design change such as eliminating exit fees for CHP customers would lead to a reduced overall capital cost for customers. Each of these policy options are described in more detail in Appendix H.

Table 4-4
Potential CHP Policy Options and Issued Addressed

	SGIP Modifications					Resource Adequacy			IOU Incentives					Rate Design Changes				Marketing and Branding							State Tax		Other Actions					R&D	Portfolio Stds
	Unbundle SGIP Incentives	Increase SGIP Incentives	Renewable CHP Bonus	Faster application processing	Application preparation assistance	Count toward resource adequacy targets	Favorable crediting of CHP capacity	Favorable crediting for RPS	CHP shareholder incentives	ERAM for CHP	CHP program funding	Utility ownership	Market-based bill credit	Net metering w/ and w/o discount	Volumetric Rate	Eliminate exit fees	Rolled-in interconnection	Coordinated education effort	Qualified provider list	Certified vendors	Low cost financing	CHP utility audits	Targeted marketing	Information sharing protocol	Tax Credit	Tax credit for suppliers	Streamlined permitting	Subsidized CHP training	CHP infrastructure	Overcome landlord tenant disconnect	Subsidized fuels	R&D Funding	CHP Portfolio Standards
Promote high value CHP (state goal)	X																					X	X		X	X				X			
Reduce capital cost	X	X	X													X	X								X	X						X	
Increase operating benefits													-	X	X						X										X	X	
Reduce hassle (siting/permitting)				X	X							X							X	X	X	X		X			X	X	X	X		X	
Education (technical knowledge/experience)					X							X						X	X	X		X	X							X			X
Resource adequacy value						X	X																										X
Reduce risk/project uncertainty																				X	X				X								
RPS value								X																									
Utility shareholder incentives									X			X																					
Lessen utility disincentives										X	X	X	X													X							X

The implementation categories are provided to clarify what type of policy action is required for implementation. For example, the Self-Generation Incentive Program (SGIP) modification policies that include unbundling the SGIP incentives and increasing the level of SGIP incentives would require CPUC rulemaking activity in order to implement these policies. Similarly, the resource adequacy and IOU incentives would also require regulatory policy changes. On the other hand, the Marketing and Branding policies, such as establishing a Energy Commission certified vendor list or establishing education and targeted marketing programs involve Energy Commission budget adjustment activity. The type of activity required to implement each policy also plays an important role in stakeholder acceptance and ease of implementation for an overall portfolio of policies as discussed later in this report.

Step 3: Develop CHP policy scenarios

In order to model these varied policy options, our team developed the following portfolios of options to capture the effects of a specific set of policies each with different objectives.

1. Base Case
2. No Incentives
3. Aggressive Market Access
4. Moderate Market Access
5. Increasing Incentives
6. Streamlining CHP Installations
7. Increasing R&D Funding
8. High Deployment
9. Portfolio Standards

For each portfolio, we developed a group of policy options that addressed the approach of that policy. For the qualitative assessment, we have delineated the policies into "core" and "supplemental." The core policies represent those policies that characterize the goal or direction of each portfolio and can be directly modeled in this analysis. The supplemental policies are included here as additional policies that can be integrated within a portfolio to offset any imbalances in the market caused by core policy implementation or to otherwise support the particular portfolio approach.

Table 4-5 shows the Base Case policy portfolio, which represents the currently existing set of core and supplemental policies in California. In this case, CHP installations can qualify for SGIP incentives (1st MW only for CHP units up to 5MW) and the electric generator gas tariff (favorable treatment of natural gas delivery charges). Additionally there are several supplemental policies and current rate structures that affect the CHP market including the existing Energy Commission Public Interest Energy Research (PIER) R&D budget under Environmentally-Preferred Advanced Generation (EPAG), the difficulty for CHP owners to export energy to the grid under existing tariffs, the utility rate structures that yield a greater savings on the customer's bill than the cost savings for the utility, and finally the proposed CARB 2007 emissions standards are significantly more strict than today's standards. We model this case from the customer, utility, and society stakeholder perspectives for 11 different CHP technologies.

Table 4-5
Base Case Policy Portfolio and Existing Supplemental Policies

Base Case Policy Portfolio
Core Policies
SGIP Incentives
CHP to qualify for UEG Gas Tariff
Supplemental Policies
CEC Technology Research and Development
Difficult to Export to the Grid for Behind the Meter CHP
Δ Customer Bill > Δ Utility Cost Savings
Proposed Tightening of Air Emissions Policy

In Table 4-6 we show the No Incentives policy portfolio. In this case, we evaluate what the CHP economics from each stakeholder perspective are if no incentives are provided to the CHP owner. This portfolio acts to isolate the effects of the incentives on the economics of CHP. The supplemental policies in the Base Case remain in effect for the No Incentives portfolio.

Table 4-6
No Incentives Policy Portfolio

No Incentives Policy Portfolio
Core Policies
Remove SGIP Incentives
Remove CHP qualification for UEG Gas Tariff

In evaluating the potential for success of each of the other policy portfolios, we added a qualitative stakeholder analysis. In addition to the costs and benefits of the three primary stakeholders in the CHP market: Customer/CHP Owner, Utility/Non-Participants and the State/Society, we also considered qualitatively the position of small consumer and ratepayer advocates are likely to take in the California policy-making process. Our analysis is not a 'last word' from any group, but rather is designed to start a dialogue among stakeholders of the proposed policy options. In Table 4-7, we define the concerns for each stakeholder that we used to consider what their perspectives would be on the specific policy options in each portfolio.

Table 4-7
Stakeholder Perspectives

Customer/ CHP Owner	Utility/ Non-Participants	State/ Society	Small User Advocate	Ratepayer Advocate
The customer's primary concern is to reduce electricity costs and maintain reliability.	The utility's primary concern is to achieve earnings targets and avoid rate increases associated with behind-the-meter CHP installations.	The society is concerned with the least cost solution with the least environmental impact.	The small user advocate is concerned with rate impacts on the small customers of California's utilities. (Similar to the positions of TURN and UCAN.)	The ratepayer advocate is concerned with keeping electric rates fair and low and promoting customer choice in energy decisions. (Similar to the position of ORA.)

Table 4-8 outlines the Moderate Market Access portfolio and introduces the stakeholder acceptance screening. In this portfolio, the core policy is the addition of the ability for CHP owners to export wholesale energy, while the Base Case policies remain in effect. The five columns to the right of the policies indicate the primary stakeholders - participants (CHP-owners), the utility, and the State (society). Additionally, we qualitatively address the perspectives we anticipate of small consumer advocates – (e.g. The Utility Reform Network (TURN) / Utility Consumers Action Network (UCAN) and ratepayer advocates (e.g. Office of Ratepayer Advocates (ORA)). Please note that we have not interviewed or asked these groups to comment, and we certainly do not intend to speak for them, but we included them because these groups represent affected stakeholders. Each group will certainly be asked to comment on proposed policy at the next step if any of these policies move closer to consideration. The letter-code is Y for Yes-support policy, N for No-do not support policy, M for Maybe - might support policy or are neutral, we use the '?' symbol if we are Uncertain as to position on policy. In some cases, the stakeholder acceptance box is left blank because they are unlikely to have a strong opinion of the particular policy. This is a high-level look at the acceptance perspectives for these stakeholders and is intended for further discussion during subsequent workshops and proceedings on future CHP policy. Informal collaboration among these stakeholders may be the most productive way to determine which policy or to innovate new approaches to policies that yield win-win outcomes, where each stakeholder benefits or is at least not harmed.

In the case of the Moderate Market Access portfolio, there is little anticipated resistance from stakeholders to the implementation of a wholesale market access policy. While we have not proposed specific rules for wholesale energy export, we evaluate the policy as if the rules can pay the CHP owner exactly the wholesale market price of energy.

Table 4-8
Moderate Market Access Policy Portfolio

Moderate Market Access Portfolio	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Maintain SGIP Incentives					
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Wholesale Energy Export	Y	M	Y	Y	Y

Table 4-9 shows the Aggressive Market policy portfolio. In this portfolio, we build upon the Moderate Market portfolio by adding two more core policies; T&D capacity support payments and CO2 credits of $8/ton per ton of CO2 saved. No stakeholders are anticipated to be particularly averse to the additional core policies if payments reflect value. However, more effort will be required from both the Energy Commission and the utilities to accurately identify and capture appropriate value of T&D capacity and CO_2.value. Note that we have evaluated the T&D capacity policy as a payment based on the actual T&D avoided costs, and the CO2 payments on the actual CO2 savings.

Table 4-9
Aggressive Market Policy Portfolio

Aggressive Market Access Portfolio	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Maintain SGIP Incentives					
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Wholesale Energy Export	Y	M	Y	Y	Y
T&D Capacity Support Payments	Y	M	Y	M	M
CO2 Credit of $8 per ton CO2 Saved	Y	M	Y	?	?

In Table 4-10, the Increasing Incentives policy portfolio, the existing SGIP policy is adjusted such that incentive level ($/MW) is increased (paid for first 5 MW on CHP units up to 20 MWs) along with additional core policies of state-level production tax credits and capital cost credits paid per kWh. Alternatively, incentives could be increased through capital cost credits and/or partial pass-through of interconnection costs for new CHP installations.

Table 4-10
Increasing Incentives Policy Portfolio

Increasing Incentives Portfolio	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Increase SGIP Incentives	Y	M	Y	N	M
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Partial pass through of interconnection costs	Y	M	Y	M	M
State tax credits (production tax credit)	Y	Y	M	--	--
State tax credits (capital cost credit)	Y	Y	M	--	--

The following three scenarios were not analyzed directly in the stakeholder cost and benefit model but were evaluated in conjunction with the CHP penetration model. In the Streamlining CHP Installations policy portfolio shown in Table 4-11 the aim was to change consumer behavior through education and targeted marketing programs. There are numerous ways to educate and provide information to consumers, so this portfolio was modeled both to allow customers to accept a longer payback period for their investment and to increase the number of smaller customers willing to considering CHP (enlarging the potential market size).

Table 4-11
Streamlining CHP Installations Policy Portfolio

Streamlining CHP Installations Portfolio	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Increase SGIP Incentives	Y	M	Y	N	M
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Education programs	Y	Y	Y		
Target marketing to the right customers	Y	M	Y		Y
Overcoming landlord/tenant barriers	Y	M	Y		Y
Free CHP assessment and auditing	Y	M	Y		Y
CEC vendor certification	Y	Y	M		
LSE qualified vendor list	Y	M	Y		

Table 4-12 represents the Increasing R&D policy portfolio which is simply the Base Case with additional funding for CHP R&D activities. As this policy would involve either changes in the budget allocation within the Energy Commission or an increase in the overall budget for CHP technologies, the State is shown here with an M, indicating the challenges to implementing budgetary changes.

Table 4-12
Increasing R&D Policy Portfolio

R&D Portfolio	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Maintain SGIP Incentives					
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Increased R&D Funding	Y	M	M	--	--

The High Deployment policy portfolio shown in Table 4-13 brings together the Aggressive Market policies, the Streamlining CHP Installations policies, and the Increased R&D policies and represents the highest achievable target for CHP installations. In this case, the limiting factor would be the overall cost requirements to implement all of these policies simultaneously.

Table 4-13
High Deployment Portfolio

High Deployment Portfolio	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Maintain SGIP Incentives					
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Wholesale Energy Export	Y	M	Y	Y	Y
T&D Capacity Support Payments	Y	M	Y	M	M
CO2 Credit of $8 per ton CO2 Saved	Y	M	Y	?	?
Increased R&D Funding	Y	M	M	--	--
Education programs	Y	Y	Y		
Target marketing to the right customers	Y	M	Y		Y
Overcoming landlord/tenant barriers	Y	M	Y		Y
Free CHP assessment and auditing	Y	M	Y		Y
CEC vendor certification	Y	Y	M		
LSE qualified vendor list	Y	M	Y		

Finally, we considered the policy of implementing Portfolio Standards for CHP as shown in Table 4-14. Portfolio Standards were not modeled in either the benefit-cost model or the CHP penetration analysis because both analyses are market based. In a Portfolio Standard approach the market penetration would be set level, rather than determined by the market.

There are several approaches that could be taken to implement a portfolio standard policy. One approach is to set the target level of CHP / CCHP penetration and then increase incentives until the target penetration goals were reached. This would be similar to an SGIP incentive (or production tax credit, capital cost credit or other incentive) that was adjusted based on the amount of new CHP installed. An alternative approach would be to implement a policy similar to the Renewable Portfolio Standard in place in California, with the electric utilities responsible for achieving the penetration targets, and the payments to encourage new CHP set by some competitive means. Establishing a competitive utility process to ‘buy’ CHP does pose problems: (1) the utility is not the main recipient of the CHP energy output, and (2) CHP projects vary significantly in technology, size, efficiency and configuration so comparison of projects in an auction or bid would be difficult. Our team generally favors policy approaches where the incentives are set based on resource benefits and the market determines the appropriate level of penetration.

Table 4-14
Portfolio Standards for CHP Policy Portfolio

Portfolio Standards for CHP	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Existing Policies					
Maintain SGIP Incentives					
Maintain CHP qualification for UEG Gas Tariff					
Core Policies					
Statewide CHP portfolio standards	Y	N	M	--	M

The supplemental policies are shown in Table 4-15. A few of these policies were included as core policies under certain scenarios described above. For example, Education Programs and Tax Credits were both included as core policies. However, in most cases, these policies would be expected to support CHP / CCHP adoption, but not have a significant impact if implemented as a stand-alone policy. We included these supplemental policies to balance the proposed policy portfolios. Note that that this analysis is designed to start a dialogue, and ultimate support depends on the details of the policy proposal. For example, a utility may not support a proposal we have marked as 'Y' (generally supportive) if implementation requires significantly more utility effort and staff time. In the case of the Electric Rate Adjustment Mechanism (ERAM) for CHP, this policy would act to mitigate the effects of revenue loss from the utility associated with increased penetration of customer-owned CHP. An ERAM allows utilities to collect a pre-authorized level of electric revenues regardless of the unit sales fluctuations. Under ERAM a balancing account is established from which any deviations of the actual electric sales from the authorized revenues (based on estimates used in setting utility rates) can be reconciled.

Table 4-15
Supplemental CHP Policy Options available to Support Core Policy Portfolios

Supplemental Policies	Participants	Utility	State	Small-User Advocate	Ratepayer Advocate
Fast and easy permitting process	Y	Y	Y		Y
Information protocol	Y	M	Y		Y
Partial pass through of interconnection costs	Y	M	Y		M
Optional market-based bill credit	Y	M	Y	Y	M
Market-based bill credit	Y	Y	M	Y	Y
Overcoming landlord/tenant barriers	Y	M	Y		Y
LSE qualified vendor list	Y	M	Y		
Education programs	Y	Y	Y		
ERAM for CHP	Y	Y	M	If in-class	M
Financial Shareholder Incentives for CHP	Y	Y	M	N	N
IOU CHP ownership	Y	M	M	N	
Count CHP toward resource adequacy (RA) requirement	Y	Y	Y	Y	Y
Expedited or assisted SGIP applications	Y	Y	Y		Y
Low cost financing	Y	Y	Y		Y
CHP program funding	Y	Y	M		
Tax credit for CHP suppliers	Y	Y	M		M
CEC vendor certification	Y	Y	M		
Free CHP assessment and auditing	Y	M	Y		Y
Target marketing to the right customers	Y	M	Y		Y

Step 4: Perform CHP stakeholder benefit-cost analysis

E3 developed a stakeholder benefit-cost model to evaluate the economics of the policy portfolios, evaluate different technologies, locations in the State, and sensitivities to important input assumptions. In this section, we present the results of the stakeholder benefit-cost analysis with a detailed report of the underlying assumptions used in the model provided in Appendix I. Note that this analysis is related, but not coordinated with the DG benefit / cost proceeding currently underway at the CPUC Rulemaking (R).04-03-017.

Our model estimates the costs and benefits on the basis of an individual technology operating within a specific customer class and utility. For example, Figure 4-2 provides the stakeholder benefit-cost analysis for a 300kW-rich burn reciprocating engine operating at an industrial customer site in SCE's territory. The bar chart on the left side of the figure indicates the benefit and cost components attributed to each stakeholder - the CHP owner, the utility, and society. Directly above the bar chart is the simple payback period for the CHP owner.

Using the base case assumptions, this 300kW-recip engine has greater benefits than costs for both the CHP owner (gain of $0.05/kWh) and Society (gain of $0.01/kWh) with a 2.11 year simple payback for the CHP owner's investment. The utility/non-participant's costs are $0.05/kWh greater than the benefits, resulting in a net cost rather than benefit.

On the right side of, Figure 4-2 the scenario is identified along with all of the sensitivity parameters. Again, the results shown in Figure 4-2 are results for base case assumptions on all input components.

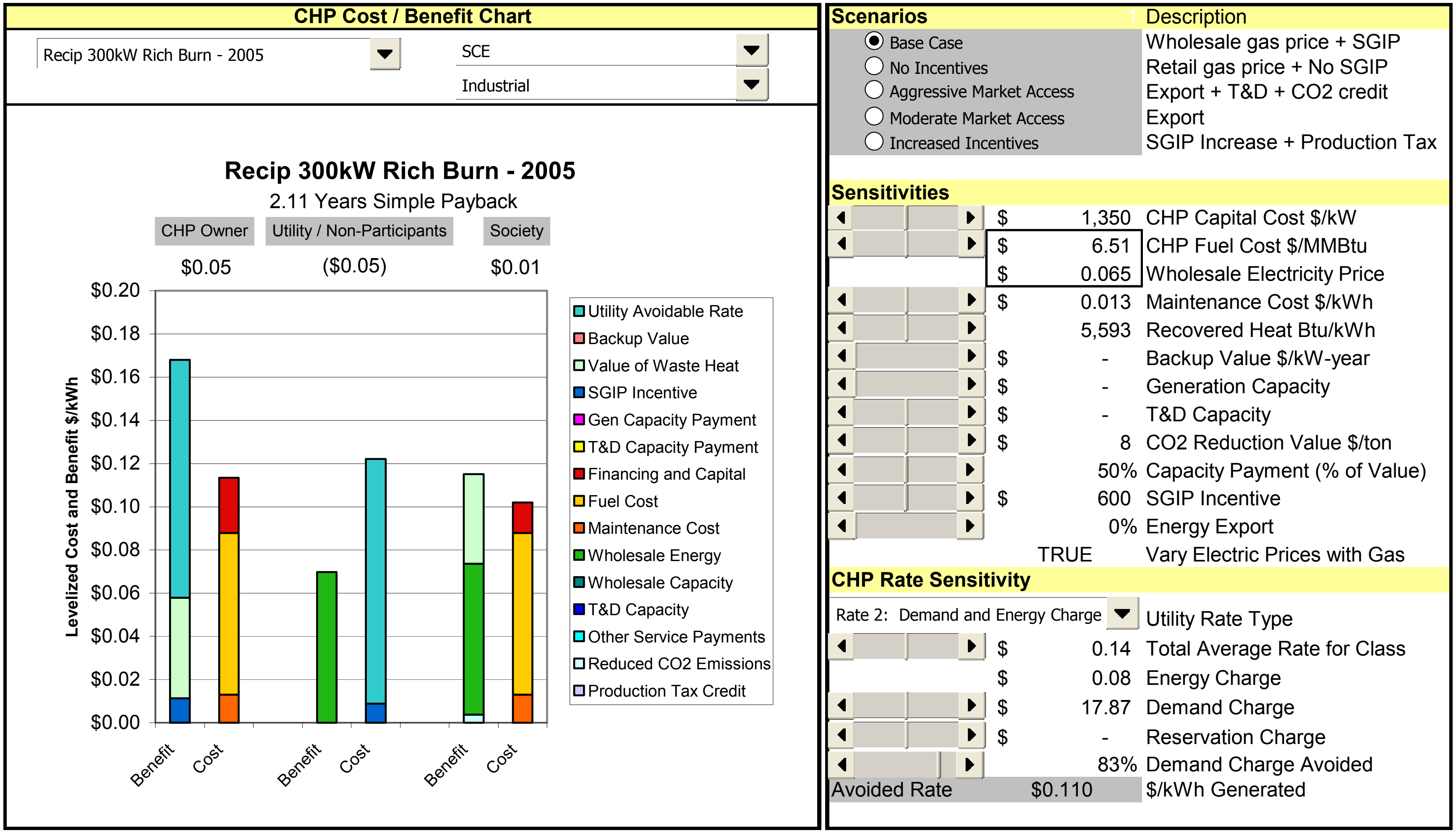


Figure 4-2
Base Case Stakeholder Benefit-Cost Results for a 300kW Rich Burn Reciprocating Engine

Figure 4-3 through Figure 4-6 show the same 300kW recip technology under the remaining four policy portfolios modeled as in our stakeholder benefit-cost model. In these figures, one can observe the change in the distribution of benefits and costs as well as the payback period associated with each set of policies.

Our team modeled 11 different CHP technologies and as would be expected there are significant differences in results among the technologies. Figure 4-7 shows a Base Case example of a 100kW microturbine operating at a commercial site in PG&E's territory. In this case, the CHP owner has a positive net benefit but both the utility and society are negative. In the case of fuel cells with higher capital costs, all three stakeholders can have negative net benefits with current technology as seen in Figure 4-8 which shows a 250kW solid oxide fuel cell (SOFC) operating at an SDG&E industrial customer site.

If the Aggressive Market Access policies were implemented and the capital costs reduced from $6,250/kW to $5,000/kW, the SOFC has a positive net benefit to the CHP owner. However, even with these assumptions, it remains a negative for both the utility and society.

With this model, the results can be calculated for each technology, policy portfolio, and input variable range and only a few illustrative examples have been shown in this report. The implications of these results are discussed in the following section and the values and input assumptions used in this model are provided in Appendix B.

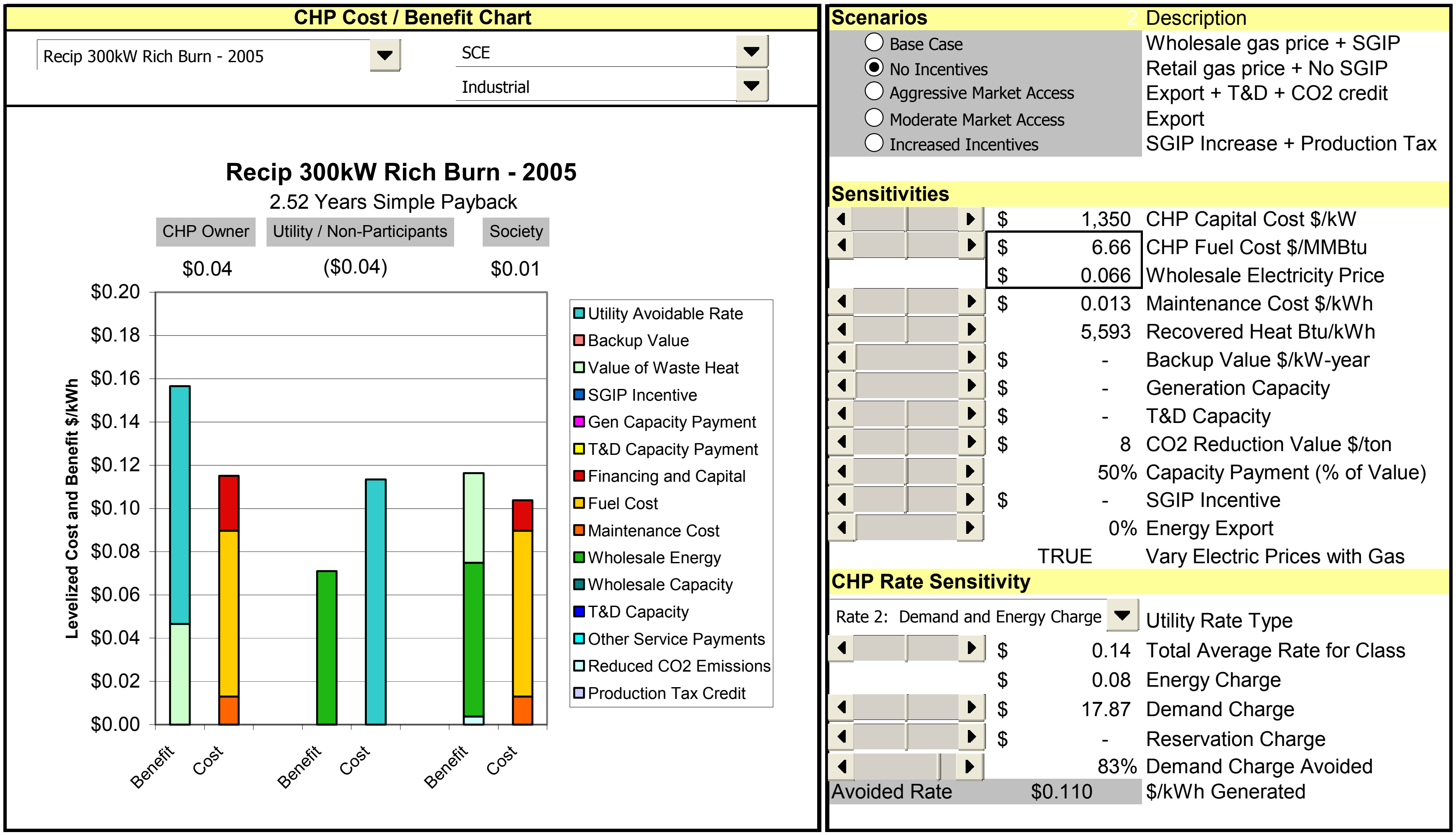


Figure 4-3
No Incentives Stakeholder Benefit-Cost Results for a 300kW Rich Burn Reciprocating Engine (in $/kwh)

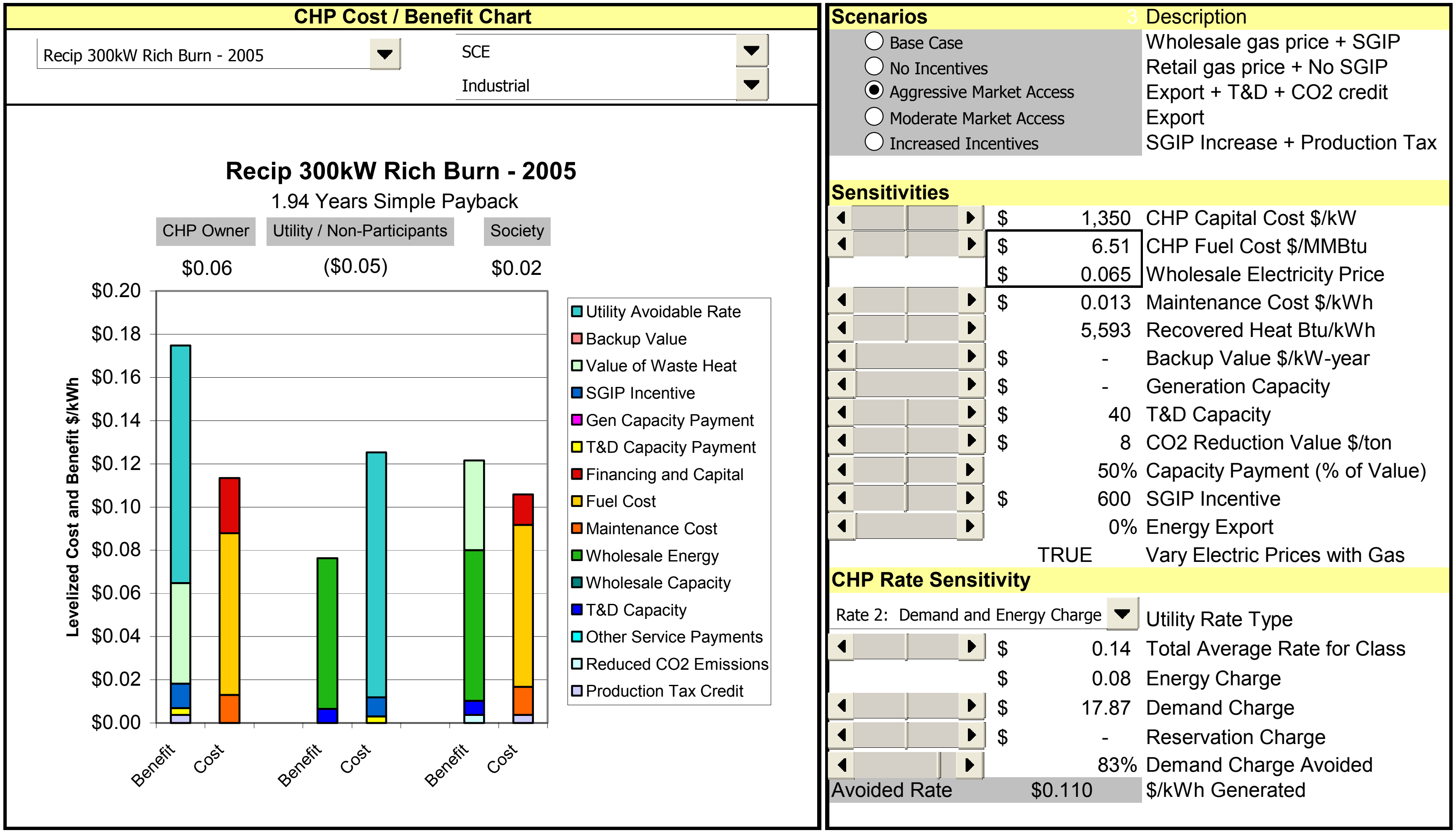
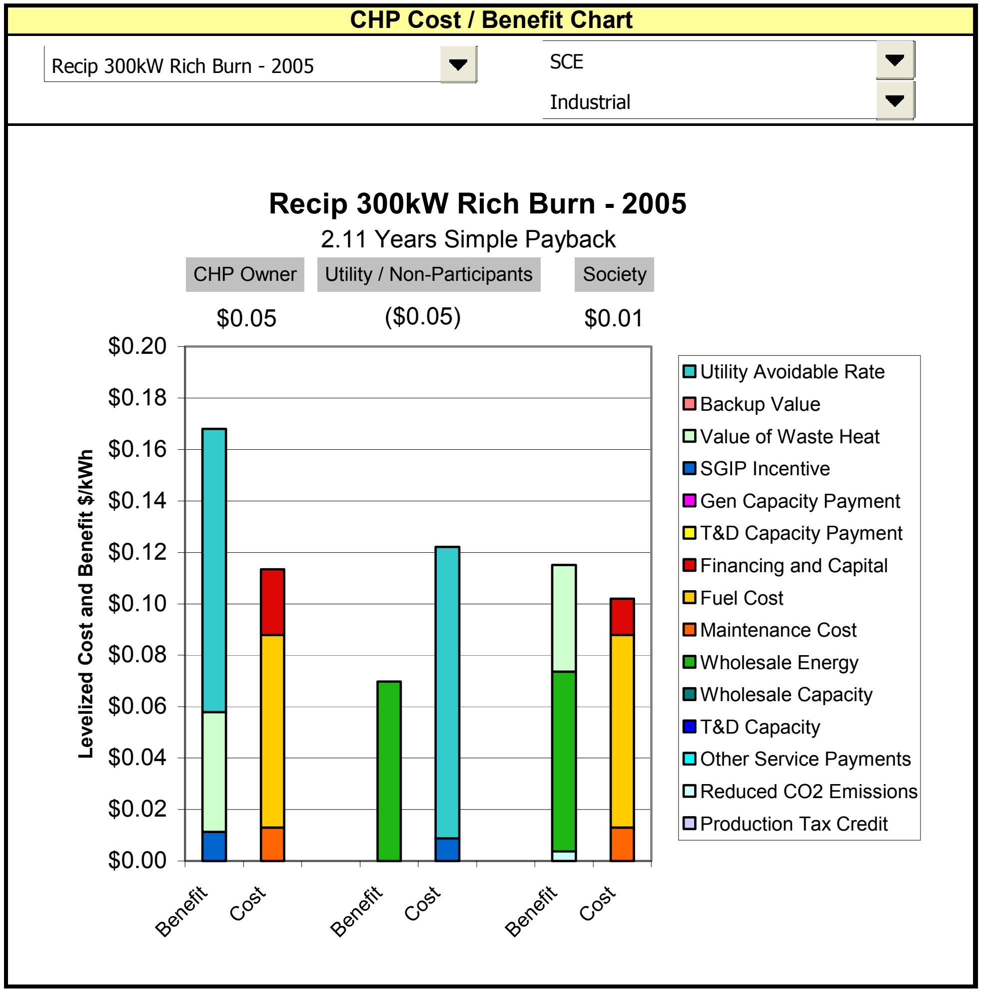


Figure 4-4
Aggressive Market Access Stakeholder Benefit-Cost Results for a 300kW Rich Burn Reciprocating Engine (in $/kwh)



Scenarios	Description
Base Case	Wholesale gas price + SGIP
No Incentives	Retail gas price + No SGIP
Aggressive Market Access	Export + T&D + CO2 credit
Moderate Market Access (selected)	Export
Increased Incentives	SGIP Increase + Production Tax

Sensitivities

$	1,350	CHP Capital Cost $/kW
$	6.51	CHP Fuel Cost $/MMBtu
$	0.065	Wholesale Electricity Price
$	0.013	Maintenance Cost $/kWh
	5,593	Recovered Heat Btu/kWh
$	-	Backup Value $/kW-year
$	-	Generation Capacity
$	-	T&D Capacity
$	8	CO2 Reduction Value $/ton
	50%	Capacity Payment (% of Value)
$	600	SGIP Incentive
	0%	Energy Export
	TRUE	Vary Electric Prices with Gas

CHP Rate Sensitivity

Rate 2: Demand and Energy Charge		Utility Rate Type
$	0.14	Total Average Rate for Class
$	0.08	Energy Charge
$	17.87	Demand Charge
$	-	Reservation Charge
	83%	Demand Charge Avoided
Avoided Rate	$0.110	$/kWh Generated

Figure 4-5
Moderate Market Access Stakeholder Benefit-Cost Results for a 300kW Rich Burn Reciprocating Engine (in $/kwh)

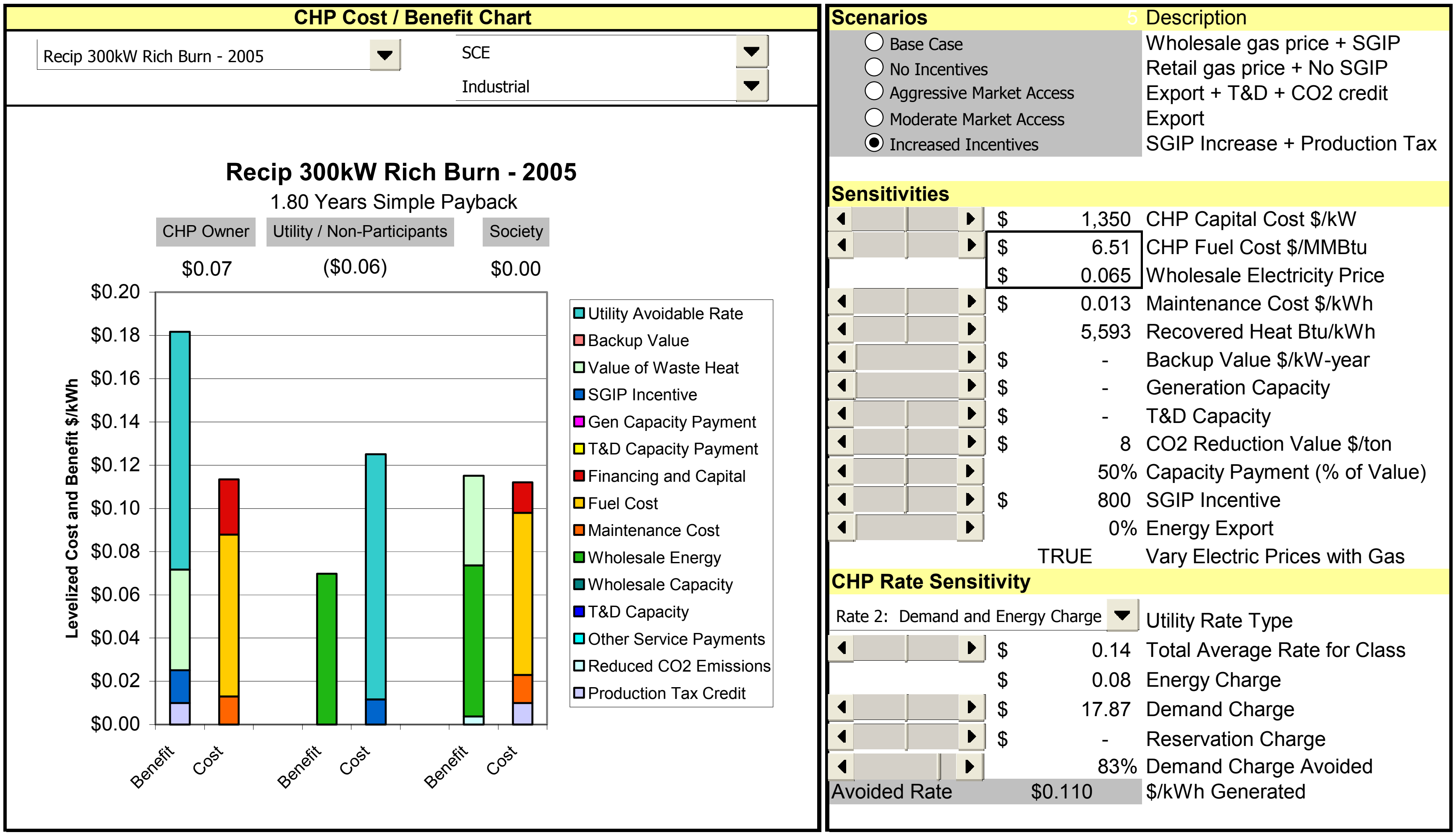


Figure 4-6:
Increased Incentives Stakeholder Benefit-Cost Results for a 300kW Rich Burn Reciprocating Engine (in $/kwh)

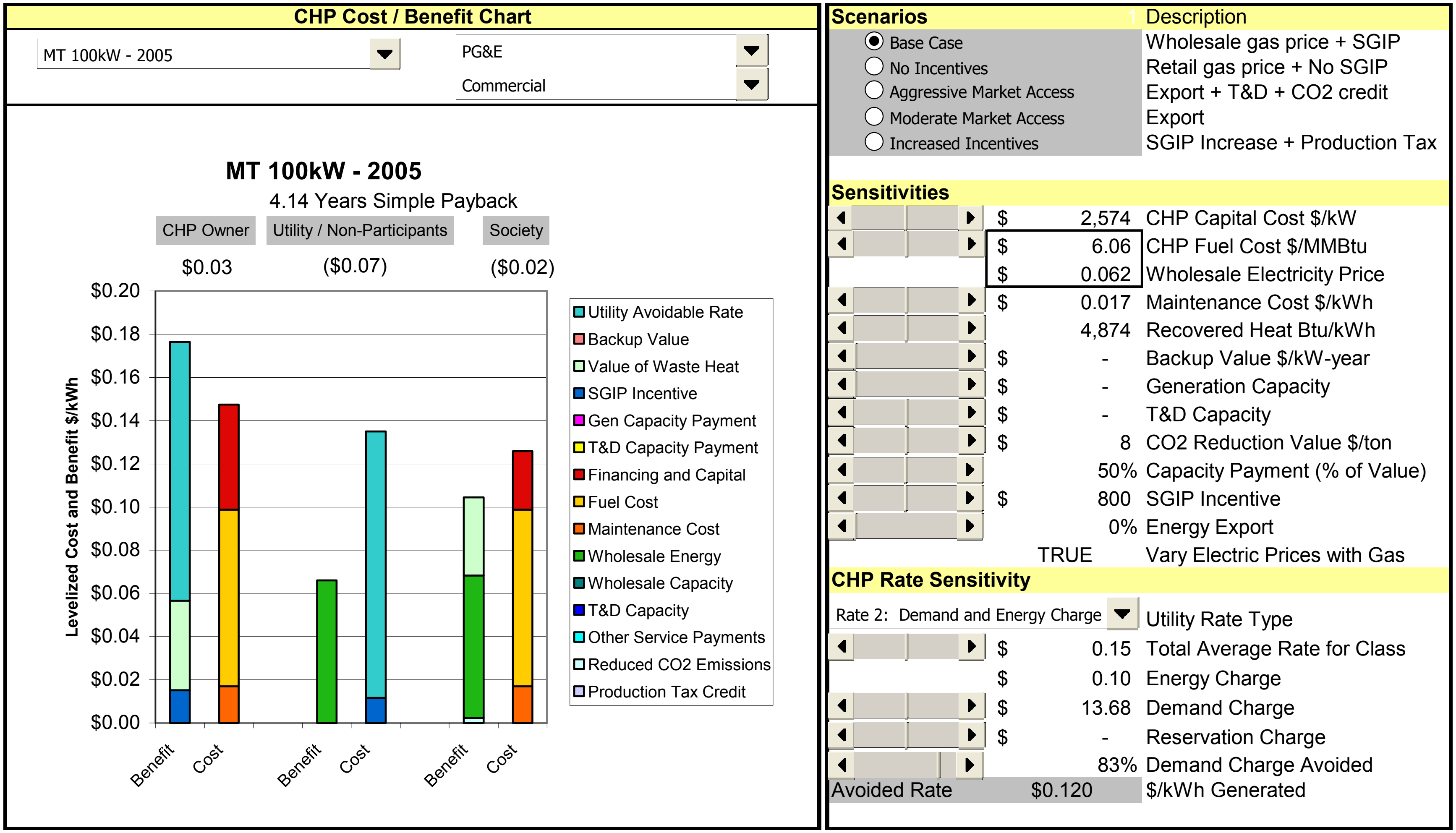


Figure 4-7:
Base Case Stakeholder Benefit-Cost Results for a 100kW Microturbine (in $/kwh)

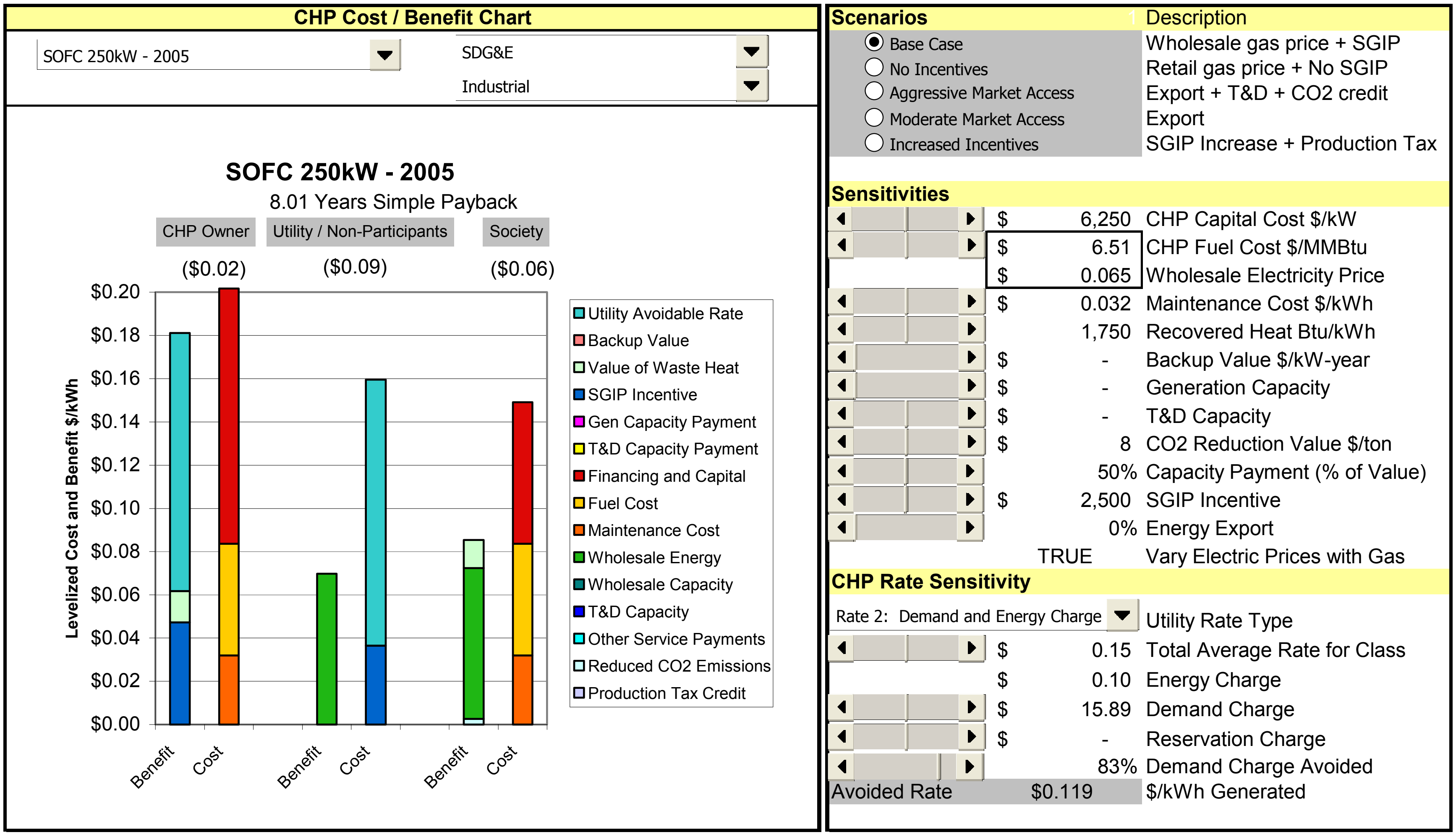
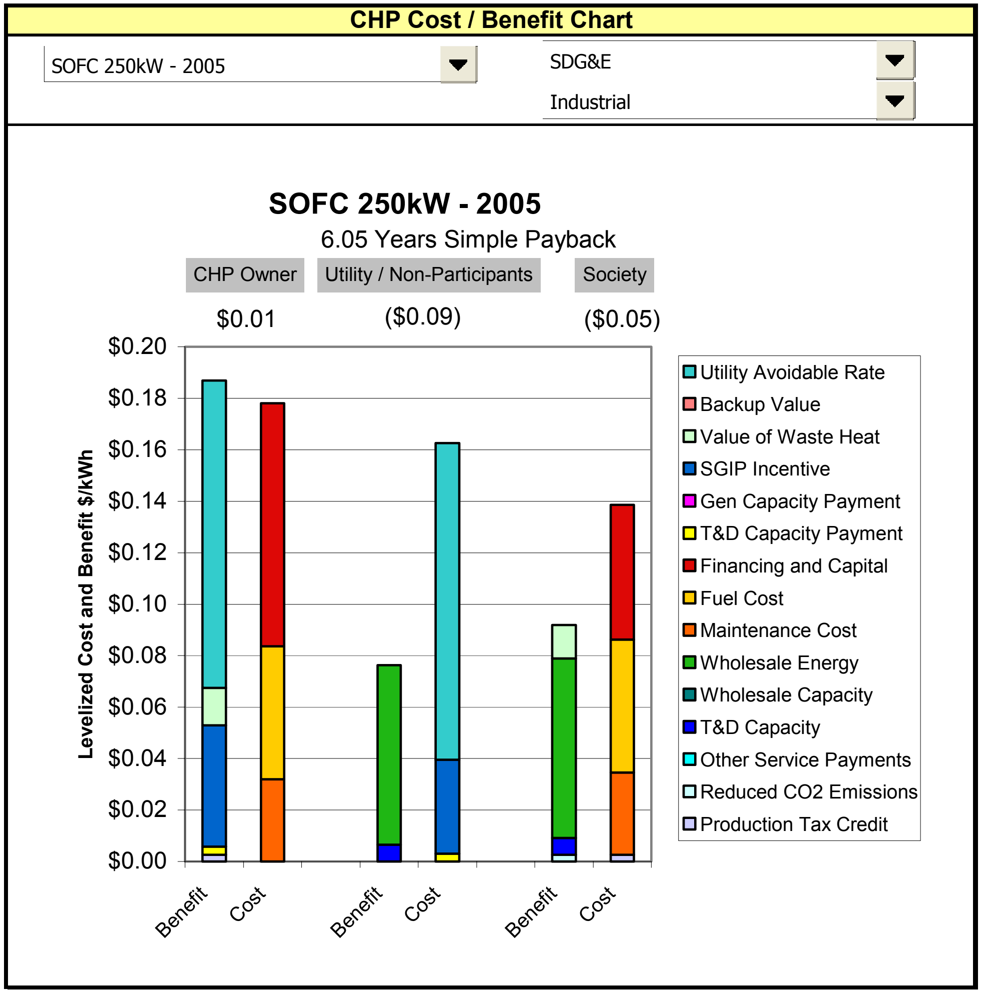


Figure 4-8:
Base Case Stakeholder Benefit-Cost Results for a 250kW Solid Oxide Fuel Cell (in $/kwh)



Scenarios	Description
○ Base Case	Wholesale gas price + SGIP
○ No Incentives	Retail gas price + No SGIP
◉ Aggressive Market Access	Export + T&D + CO2 credit
○ Moderate Market Access	Export
○ Increased Incentives	SGIP Increase + Production Tax

Sensitivities

$	5,000	CHP Capital Cost $/kW
$	6.51	CHP Fuel Cost $/MMBtu
$	0.065	Wholesale Electricity Price
$	0.032	Maintenance Cost $/kWh
	1,750	Recovered Heat Btu/kWh
$	-	Backup Value $/kW-year
$	-	Generation Capacity
$	40	T&D Capacity
$	8	CO2 Reduction Value $/ton
	50%	Capacity Payment (% of Value)
$	2,500	SGIP Incentive
	0%	Energy Export
	TRUE	Vary Electric Prices with Gas

CHP Rate Sensitivity

Rate 2: Demand and Energy Charge		Utility Rate Type
$	0.15	Total Average Rate for Class
$	0.10	Energy Charge
$	15.89	Demand Charge
$	-	Reservation Charge
	83%	Demand Charge Avoided
Avoided Rate	$0.119	$/kWh Generated

Figure 4-9:
Aggressive Market Access Stakeholder Benefit-Cost Results for a 250kW Solid Oxide Fuel Cell with reduced capital costs from $6,250/kW to $5,000/kW (in $/kwh)

Policy Scenarios and CHP Penetration Results

The results described above are the benefit-cost implications for a single CHP applications in specific locations. The penetration impacts were then estimated over time by EEA across all of the technologies and customer segments and then compute the present value. Since a number of portfolios addressed increased adoptions rates and market assessment, only portfolios 1 through 5 were evaluated individually. Portfolios 1 through 8 were evaluated in the penetration analysis and the assumptions used in both analyses are provided in Table 4-16.

Figure 4-10 is shown again here to illustrate the combined results of the E3 policy analysis and EEA penetration analysis. The results show a marked increase in penetration and societal benefit for those scenarios that allow for wholesale market export. In these cases, customers can install CHP units sized for the on-site thermal loads and export excess electricity. Since the majority of smaller loads use more electricity than thermal energy, this primarily benefits the very large CHP applications.

Also, the Increased Incentives scenario yields an extremely low societal benefit because the savings from CHP installations are transferred to CHP owner through larger incentives in the form of a production tax credit.

Table 4-16
Policy Scenarios and Link to CHP Penetration Model

Scenarios	Policies included in E3 model	Implication to EEA Model
Base Case	• SGIP • Electric generator gas prices • Waived departing load fees (for certain CHP technologies)	None - Base Cases are modeled using the same assumptions
No Incentives	• Remove SGIP • Remove Electric generator gas prices	• Remove SGIP • Remove electric generator gas prices • Add in departing load fees (utility specific)
Moderate Market Access	Base case plus: • Wholesale generation export	• Add wholesale generation export (6.6 cents/kWh)
Aggressive Market Access	Base case plus: • T&D capacity markets • Wholesale generation export • CO_2 credit	• Add T&D Capacity value ($40/kW-yr) • Add wholesale generation export (6.6 cents/kWh) • Add CO_2 value at $8/ton avoided
Increased Incentives	Base case plus: • Increase SGIP • Add a production tax credit	• Increase SGIP amount/ size applicability • Add a production tax credit ($0.01/kWh)
Streamlining		• Project payback acceptance curve shifted out by one year (e.g. customer would be willing to accept a payback of 3 years rather than 2 years) • Increase share of customers willing to consider CHP (increase market size)
Technology R&D		• Accelerate rate of technical change by 5 years
High Deployment		• Add T&D Capacity value ($25/kW-yr) • Add wholesale generation export (6.6 cents/kWh) • Add CO_2 value at $8/ton avoided Accelerate rate of technical change by 5 years • Project payback acceptance curve shifted out by one year (e.g. customer would be willing to accept a payback of 3 years rather than 2 years) • Increase share of customers willing to consider CHP (increase market size)

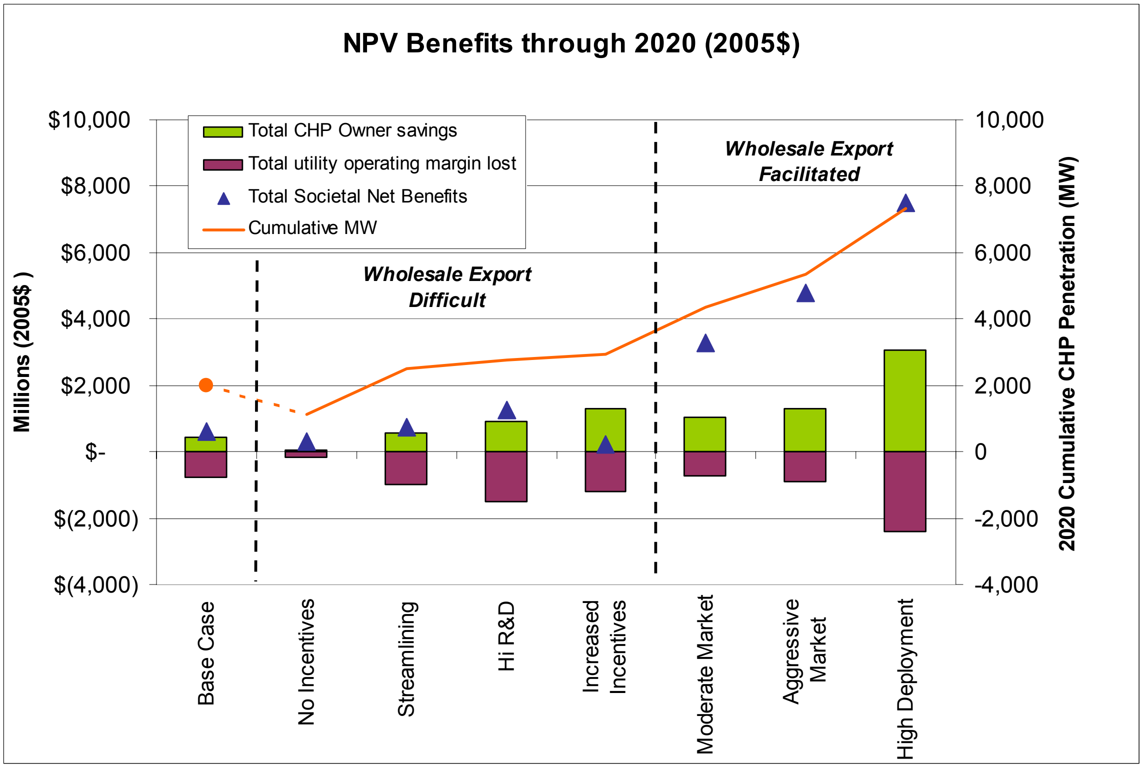


Figure 4-10
Stakeholder Results of Policy Scenarios and CHP Penetration Levels in 2020

Incentive Exit Strategy and Portfolio Combinations

The policy portfolios that we propose generally take a single approach to encouraging CHP adoption, for example, increasing access to markets, increasing incentives, investing in R&D, and others. The existing policy, and future policies, however, will likely be some combination.

We suggest an approach that combines policy portfolios to achieve the short- and long-term Energy Commission goals as shown graphically in Figure 4-11, below. The idea is to ensure ‘market based’ payments are made for CHP installations based on the market prices of services they provide (for example, energy and capacity, CO2 reductions) and then add an incentive payment that is sufficient to encourage new CHP activity. The incentive payment can then be ramped down over time as technology cost and performance improves, the market matures, and projects can tolerate a lower incentive payment. This approach provides a clear exit strategy to the incentive, and also rewards CHP installations that provide system benefits through market – based payments. This approach would require a change to SGIP, however, since SGIP-funded CHP cannot participate in other incentive programs.

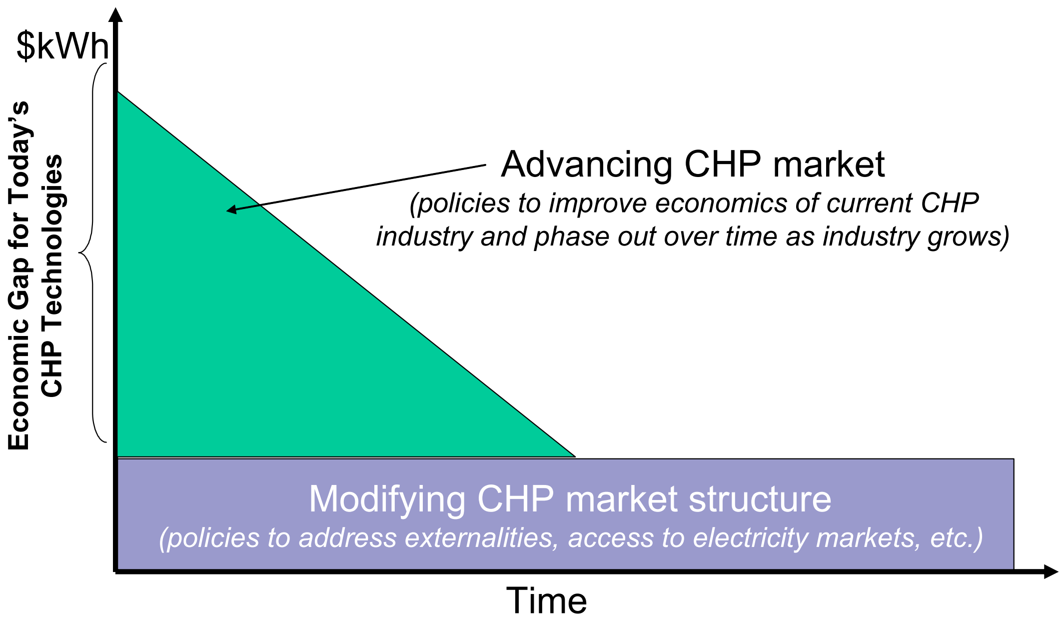


Figure 4-11
Combining Policy Portfolios and Exit Strategy

Conclusions and Implications

The market penetration analysis from Chapter 2 has shown that with existing policy we project approximately 2 GW of installed CHP by 2020 across a range of customer types and CHP technologies and applications. Our analysis shows that this would result in approximately $451 million in CHP owner benefits, $620 million in societal benefits, and $759 million in electric utility losses. The utility loss problem results from larger avoided utility bills than corresponding utility savings and will ultimately lead to rate increases for other customers. On the whole, there are significant positive societal benefits in the existing approach, including a reduction of 36 million tons of CO_2 through 2020. In our analysis, removing the CHP incentives significantly reduces CHP adoption and societal benefits.

The challenge is then to determine if any additional policies could be adopted that improve on the approach California has taken to encourage CHP. Ultimately, improvement is subjective, but in our analysis we consider the following stated goals of proposed new policy;

- Meet stakeholder goals; including for example,
  - Higher efficiency use of the State's energy resources
  - Positive environmental impact
  - Low impact on utility rates and minimal cost-shifting
- Promote best projects (as defined by stakeholder goals)
- Be relatively easy to implement
- Require low incentive payments

- Have a realistic exit strategy

The policy portfolios that best meet these criteria are those that introduce market-based payments for services, either wholesale electricity, generation capacity, and T&D capacity. These approaches would align incentives of the CHP owner to operate CHP when it will also help the utility system. Currently, existing CHP installations are designed and operated to maximize CHP owner's energy cost savings. Additionally, the existing SGIP incentives are based on installed CHP size, technology, and type of fuel and not on output or efficiency. By creating the right operating agreements with CHP units, these policy approaches can integrate the State's investment in CHP into our resource planning which is currently lacking.

Policies that involve paying for services that can be metered and verified is *likely* to face less opposition from ratepayer or small consumer advocates than increasing incentives. Payments for verified services would not lead to either reduced utility operating margin or rate increases. Our team continues to work on projects to define the policy initiatives that are agreeable to multiple stakeholders and know this is not easy, but agreements ultimately linked to value should be easier to reach consensus on and provide the greatest societal benefit.

Also, with a market-based policy, the exit strategy is better defined as a transition from the existing incentives based policy to payment for services. Once all payments are based on services, then the period of market subsidy is effectively complete.

The alternative approach to increasing CHP adoption rate is to increase incentives through SGIP or introduction of a production tax credit, capital cost credit or other mechanism. If these incentives are not linked to CHP performance and coordinating CHP with the market, they will not change the fundamentals of the California CHP market, and will reduce available funding for other uses. Increasing incentives across the board would also result in payments to some CHP installations that are higher than necessary for the project to go forward.

5
ANALYSIS OF R&D NEEDS FOR INCREASED CHP MARKET PENETRATION

The goal of this analysis is to provide the Energy Commission with recommendations for the research and development activities which could lead to increases in CHP market penetration. To perform this assessment EPRI:

- Evaluated the technology and penetration barriers identified by the CHP market assessment - Chapter 2
- Evaluated the end-user market research findings – Chapter 3
- Examined the results of the cost and benefits of policy incentives – Chapter 4
- Prepared recommendations for research that could increase the penetration of CHP by 2020.

The findings from the market analysis in Chapter 2 indicate there are certain specific R&D activities which could improve the market penetration of CHP and the benefits and the rewards for the State in-general could be large as illustrated in Chapter 4. For example of the 30,000 MW of technical market potential, only about 2,000 MW is currently cost effective primarily due to economic considerations and restrictive environmental emission criteria. The technical potential in the commercial sector alone is about 9,000 MW of which only about 1,400 MW was estimated to be economic in the study period. This suggests the need for continued R&D towards technologies and systems that would be most suitable for this market sector.

Technology Needs and Gaps

A critical factor for CHP market penetration is the ability to be both cost competitive and to have acceptable environmental emission levels. Because the State's current 2007 emission regulations are so restrictive, near-term R&D actions by the Commission should address the following areas:

- Ensure market availability of low emission gas turbines and internal combustion engines. Develop and demonstrate low NOx emission control systems for these technologies and demonstrate solutions are viable in the field through end-use demonstrations.

Longer term R&D activities by the Commission, should focus on achieving more significant capital cost reductions of CHP options – particularly smaller systems for the commercial sector and light industrial markets. R&D efforts should focus on improving the cost of current non-competitive micro turbines and high temperature fuel cells. Market research points that payback times are too long for many commercial sector market applications, suggesting that current retail rates may be competitive.

R&D efforts should address:

- Improving durability and reducing O&M costs of emerging CHP technologies
- Increasing electrical efficiency
- Reducing the capital and installation costs of fully integrated packaged systems
- Defining and standardizing packaged systems for specific California end-use markets
- Accelerating the development, demonstration and adoption of very low emission high temperature fuel cells such as solid oxide fuel cell technology
- Integrating electrical energy storage systems and thermal energy storage with CHP systems to provide an increased value proposition to end-users.
- Assessing the potential for standardized CHP systems/ appliances for California's mass market sector.

Market Transformation Roadmap

While not part of the scope of this study, research is needed to develop an industry roadmap to define appropriate target levels for the State's CHP market penetration and to develop specific technology and policy actions to reach those levels. The Roadmap should consider a combination of both policy and R&D activities to achieve market goals. Some of the areas which need further research include:

- More in- depth assessments of the specific target market segments identified in Chapter 2 to better understand the extent of the opportunity, the structure and decision making criteria of the industry, and the specific technology fits and energy characteristics of the application.
- Research to support continued development of policy actions that promote CHP development with the broadest benefits, and specifically analysis and stakeholder collaboration to develop a win-win approaches for all key State stakeholders.

Demonstrations of Standardized, Packaged Systems

R&D is needed to address the perceived risks of emerging CHP systems. These risks could be reduced through:

- Definition of standard CHP packaged systems for target markets
- Pre-qualification, testing and certification of these systems
- Development and validation of seamless interconnection solutions with the ability to export power.

6 CONCLUSIONS

- Despite higher natural gas prices, the market potential for CHP remains substantial and could contribute significantly to the State's overall Energy Action Plan. The base case market penetration for CHP is near 2,000 MW which is about half that of a 1999 forecast that was based on gas prices that were much lower than the current forecast.18 The high level of gas prices makes competition more difficult for CHP with correspondingly longer paybacks and lower acceptance levels among potential adopters.
- Reciprocating engine systems, the dominant technology in markets less than 5 MW, are unable to meet the accelerated 2007 emissions requirements in the Southern California until 2010. In addition, small gas turbines will require very expensive after-treatment emission control systems until that technology improves. Consequently, there is no market penetration in the Southern California during the first 5 years for systems less than 20 MW.
- Market penetration of emerging technologies such as fuel cells and microturbines remains very low throughout the forecast period due to uncompetitive early market pricing that is not offset by the SGIP payments.
- The difficulty in selling excess electricity from a CHP generator leaves the 5,200 MW potential market untapped. The market requires scheduling hour-by-hour exports with the CAISO, and finding an electricity buyer. A policy that encourages electric utilities to purchase electricity from CHP as delivered at the prevailing wholesale price could address this problem and encourage larger CHP installations in facilities that use significant amounts of thermal energy. This could look like 'net metering' at the wholesale energy price.
- Energy cost savings and reliability/security are the key drivers for California end-users to adopt CHP, however, payback requirements of less than 3 years will limit adoption.
- Policy options that energy users said would most likely increase the odds of a CHP project going forward were: modifying the SGIP so that larger projects could participate; and allowing CHP owners to sell excess power to the grid.
- Consider policy options that encourage CHP operation at times of high system and local T&D value. These 'market access' policies can replace or reduce SGIP incentives over time and can reduce utility operating margin losses by increasing utility system benefits of CHP. Operating CHP to capture both owner and utility benefits also results in higher societal benefits. For example, paying CHP owners for an operating agreement to ensure that the unit is running during critical peak days, during a local T&D capacity constraint, and/ or at times of high electricity market prices.

[18] *Market Assessment of Combined Heat and Power in the State of California*, prepared by Onsite Sycom Energy Corporation, California Energy Commission Report P700-00-009, July 1999 (released October 2000.)

7
RECOMMENDATIONS

Policy Considerations

From the policy perspective, the team's main recommendation is to shift towards policies that provide payments for utility-side services and decrease incentive payments with no operational requirements. This approach coordinates operation of CHP / CCHP to capture both customer-side and utility-side benefits simultaneously. This approach follows the recommendations of the California Energy Commission-sponsored DER Public/Private Partnership to focus on win-win opportunities, where multiple stakeholders benefits and no stakeholders are harmed.

A move towards payment for service, rather than incentive, over time will result in;

- Increased penetration of CHP / CCHP which typically have higher efficiency than central station generation,
- Decreased economic losses to the electric utility and non-participating customers relative to the SGIP incentive approach,
- A clearer exit strategy that ultimately eliminates all incentive 'subsidies' and has only payments based on services CHP / CCHP provides,
- Higher societal benefits because both customer and utility benefits are provided,
- Less resistance from stakeholders than increasing subsidies because payments are matched with benefits, and rate impacts are therefore lower.

Our analysis considered a number of policies of this type that pay for generation capacity, energy (including losses), T&D capacity, and CO_2 mitigation benefits of CHP. We focused on these policies because they provide the largest benefits for most CHP / CCHP installations, however, this list is not comprehensive. The CPUC DG Costs and Benefits proceeding is also defining services that DG could potentially provide An informal stakeholder collaborative process should be used to develop and assess innovative policy options that provide benefits to all stakeholders

The specific policies of this type that we consider in our analysis, and we recommend further investigation into, include:

- Opening the market for electricity export to the grid, particularly for large CHP installations, through an approach similar to 'net metering' for renewables but at the wholesale electricity price.
- Payment for T&D capacity through an operating agreement for CHP / CCHP with physical assurance in capacity constrained areas.

- Payment for availability during system peak times based on generation capacity value to improve resource adequacy.
- Payment based on CO_2 mitigation CHP achieves through higher efficiency through a production tax credit in $/kWh.

For our analysis we assumed that policies could be structured that would make payments based on the actual value of these services. We recommend that a facilitated informal stakeholder collaboration be used to develop, assess, and gain buy in of policies that benefit all stakeholders. The next step by the State would be to develop explicit policy mechanisms with stakeholders (likely in CPUC proceeding) to consider such issues as contract and operating agreement details, basis of payments, metering, solicitation, and other factors.

R&D Considerations

To close the gap between the estimated technical market potential and the economically viable market size estimated in this study, and the Energy Commission should continue R&D efforts that address the following:

- Ensure market availability of low emission gas turbines and internal combustion engines for CHP markets. Demonstrate solutions are viable in the field through end-user demonstrations
- Improve durability and reduce O&M costs of emerging CHP technologies
- Increase electrical efficiency
- Reduce the capital and total installed costs of fully integrated packaged systems
- Define and standardize packaged CHP systems for specific high value California end-use markets
- Accelerate the development, demonstration and adoption of very low emission high temperature fuel cells such as solid oxide fuel cell systems.
- Improve the integration of electrical energy storage systems with CHP products to provide an increased value proposition to end-users.
- Assess the potential for standardized CHP systems/ appliances for California's mass market sector.
- Support continued development of policy actions and specifically stakeholder collaboration and analysis to develop win-win opportunities for all key State stakeholders.
- Develop and validate low cost, and seamless interconnection solutions for CHP systems with the ability to export power.

A

APPENDIX: EXISTING CHP DETAILED TABLES

Table A-1
Existing CHP Operating in 2004 by Size and Application

		<1 MW		1 - 4.9 MW		5 - 19.9 MW		20 - 49.9 MW		50 - 99.9 MW		> 100 MW		Total	
	Application	**Sites**	**MW**	**Sites**	**MW**	**Sites**	**MW**	**Sites**	**MW**	**Sites**	**MW**	**Sites**	**MW**	**Sites**	**MW**
Industrial	SIC 20: Food	13	4.3	9	23.9	8	64.3	10	374.1	2	108.8	5	776.0	47	1,351.4
Industrial	SIC 22:Textile Products	2	0.7	1	1.1									3	1.8
Industrial	SIC 24:Wood Products	1	0.8	2	7.0	8	70.7	8	233.0					19	311.6
Industrial	SIC 26: Paper			1	1.4	2	25.5	11	390.1	1	69.5			15	486.5
Industrial	SIC 27: Publishing	1	0.1	2	5.7	1	5.0							4	10.8
Industrial	SIC 28: Chemicals	3	1.1	4	9.4	3	26.2	3	109.8	2	136.5	1	108.0	16	391.0
Industrial	SIC 29: Petroleum Refining			2	6.2	2	21.0	4	159.9	6	482.9	2	541.4	16	1,211.4
Industrial	SIC 30: Rubber							1	27.0					1	27.0
Industrial	SIC 32: Stone, Clay, Glass	3	1.2	2	2.4			2	72.4					7	75.9
Industrial	SIC 33: Primary Metals	4	0.5	1	1.1							1	493.0	6	494.5
Industrial	SIC 34: Fabricated Metals	13	2.2											13	2.2
Industrial	SIC 35: Machinery	2	1.1											2	1.1
Industrial	SIC 36: Electrical Equipment	1	0.9	2	4.5									3	5.4
Industrial	SIC 37: Transportation Equip			1	2.4	1	9.5							2	11.9
Industrial	SIC 39: Misc Manufacturing	3	0.3	2	7.5	2	16.8							7	24.6
	Total Industrial	46	13.2	29	72.4	27	239.0	39	1,366.3	11	797.7	9	1,918.4	161	4,407.0
Other	SIC 9900: Unknown	6	1.5			1	8.0							7	9.6
Other	SIC 01: Agriculture	5	1.4			2	12.2	1	25.0					8	38.5
Other	SIC 13: Crude Oil	9	2.3	13	45.7	26	239.6	27	1,107.3	3	187.7	5	1,274.0	83	2,856.7
Other	SIC 14: Quarrying							1	45.0	1	55.4			2	100.4
	Total Other	20	5.2	13	45.7	29	259.8	29	1,177.3	4	243.1	5	1,274.0	100	3,005.2
Commercial	Storage			1	1.4			2	56.0	1	71.5			4	128.9
Commercial	SIC 4500: Air Transportation	1	0.5			1	8.0	1	30.0					3	38.5
Commercial	SIC 4800: Communications			2	3.7									2	3.7
Commercial	SIC 4939: Utilities	6	2.0	3	8.8	4	41.3			1	95.0	3	426.3	17	573.3
Commercial	SIC 4952: Wastewater Treatment	9	2.2	5	10.5	4	42.4	1	49.4					19	104.5
Commercial	SIC 4953: Solid Waste Facilites			2	3.3			2	65.3					4	68.6
Commercial	SIC 4961: District Energy			2	2.9	1	7.5							3	10.4
Commercial	SIC 5000: Wholesale/Retail	3	0.9											3	0.9
Commercial	SIC 5411: Food Stores	3	0.7											3	0.7
Commercial	SIC 5812: Restaurants	7	0.1											7	0.1
Commercial	SIC 6512: Comm. Building	24	6.3	7	15.0	1	6.0							32	27.3
Commercial	SIC 6513: Apartments	23	1.5											23	1.5
Commercial	SIC 7011: Hotels	50	7.1	2	2.7									52	9.8
Commercial	SIC 7200: Laundries	64	1.1											64	1.1
Commercial	SIC 7542: Carwashs	1	0.0											1	0.0
Commercial	SIC 7990: Amusement/ Rec.	42	3.9					1	49.8					43	53.7
Commercial	SIC 8051: Nursing Homes	15	1.9	1	3.0									16	4.9
Commercial	SIC 8060: Hospital/Healthcare	25	9.1	9	14.9	2	10.8	3	90.3					39	125.1
Commercial	SIC 8211: Schools	86	6.1											86	6.1
Commercial	SIC 8220: Colleges/Univ.	20	4.4	4	8.7	5	54.3	5	181.2					34	248.5
Commercial	SIC 8300: Comm Services	1	0.5	1	1.4									2	1.9
Commercial	SIC 8400: Zoos/Museums			1	1.4									1	1.4
Commercial	SIC 8800: Households	21	0.3											21	0.3
Commercial	SIC 8900: Services NEC	4	0.5	2	5.1									6	5.6
Commercial	SIC 9100: Government Fac.	8	3.2	5	9.0			1	29.0					14	41.2
Commercial	SIC 9200: Courts/Prisons	2	0.8	1	2.7	1	7.0	3	93.4					7	103.9
Commercial	SIC 9700: Military	1	0.1	3	7.9	1	7.2	4	140.6					9	155.7
	Total Commercial	416	53.1	51	102.2	20	184.4	23	785.0	2	166.5	3	426.3	515	1,717.6
	Grand Total	**482**	**71.5**	**93**	**220.4**	**76**	**683.2**	**91**	**3,328.6**	**17**	**1,207.3**	**17**	**3,618.7**	**776**	**9,129.8**

Table A-2
Existing CHP Operating in 2004 by Size and Fuel Type

		Biomass		Coal		Natural Gas		Oil		Waste		Wood		Other		Total	
	Application	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
Industrial	SIC 20: Food	2	25.0	2	57.5	41	1,265.9							2	3.0	47	1,351.4
Industrial	SIC 22:Textile Products					3	1.8									3	1.8
Industrial	SIC 24:Wood Products			1	44.0	1	49.5					17	218.1			19	311.6
Industrial	SIC 26: Paper					13	453.0			1	20.0	1	13.5			15	486.5
Industrial	SIC 27: Publishing					3	10.7							1	0.1	4	10.8
Industrial	SIC 28: Chemicals			2	170.5	7	126.0	1	1.9	2	81.8			4	10.8	16	391.0
Industrial	SIC 29: Petroleum Refining					8	834.5			5	311.0			3	65.9	16	1,211.4
Industrial	SIC 30: Rubber									1	27.0					1	27.0
Industrial	SIC 32: Stone, Clay, Glass					6	51.9			1	24.0					7	75.9
Industrial	SIC 33: Primary Metals					6	494.5									6	494.5
Industrial	SIC 34: Fabricated Metals					13	2.2									13	2.2
Industrial	SIC 35: Machinery					2	1.1									2	1.1
Industrial	SIC 36: Electrical Equipment					2	4.5	1	0.9							3	5.4
Industrial	SIC 37: Transportation Equip					2	11.9									2	11.9
Industrial	SIC 39: Misc Manufacturing					6	17.4			1	7.2					7	24.6
	Total Industrial	2	25.0	5	272.0	113	3,324.9	2	2.8	11	471.0	18	231.6	10.0	79.8	161	4,407.0
Other	SIC 9900: Unknown					6	9.4							1	0.1	7	9.6
Other	SIC 01: Agriculture	1	25.0			7	13.5									8	38.5
Other	SIC 13: Crude Oil			3	124.7	72	2,657.2	3	8.9	2	0.4			3	65.5	83	2,856.7
Other	SIC 14: Quarrying					2	100.4									2	100.4
	Total Other	1	25.0	3	124.7	87	2,780.6	3	8.9	2	0.4	0	0.0	4.0	65.6	100	3,005.2
Commercial	Storage					4	128.9									4	128.9
Commercial	SIC 4500: Air Transportation					2	38.0							1	0.5	3	38.5
Commercial	SIC 4800: Communications					2	3.7									2	3.7
Commercial	SIC 4939: Utilities	2	5.8			11	549.9			1	17.0			3	0.6	17	573.3
Commercial	SIC 4952: Wastewater Treatment	9	25.6			10	78.9									19	104.5
Commercial	SIC 4953: Solid Waste Facilites	2	3.3			1	29.7			1	35.6					4	68.6
Commercial	SIC 4961: District Energy	1	1.3			2	9.1									3	10.4
Commercial	SIC 5000: Wholesale/Retail					3	0.9									3	0.9
Commercial	SIC 5411: Food Stores					3	0.7									3	0.7
Commercial	SIC 5812: Restaurants					6	0.1							1	0.1	7	0.1
Commercial	SIC 6512: Comm. Building					31	27.2							1	0.1	32	27.3
Commercial	SIC 6513: Apartments					22	1.4							1	0.1	23	1.5
Commercial	SIC 7011: Hotels					49	9.2							3	0.6	52	9.8
Commercial	SIC 7200: Laundries					62	1.0							2	0.03	64	1.1
Commercial	SIC 7542: Carwashs					1	0.0									1	0.0
Commercial	SIC 7990: Amusement/ Rec.					39	53.1							4	0.7	43	53.7
Commercial	SIC 8051: Nursing Homes					14	4.8							2	0.1	16	4.9
Commercial	SIC 8060: Hospital/Healthcare					39	125.1									39	125.1
Commercial	SIC 8211: Schools					80	5.7							6	0.4	86	6.1
Commercial	SIC 8220: Colleges/Univ.					31	246.5							3	2.0	34	248.5
Commercial	SIC 8300: Comm Services					2	1.9									2	1.9
Commercial	SIC 8400: Zoos/Museums					1	1.4									1	1.4
Commercial	SIC 8800: Households					20	0.3							1	0.01	21	0.3
Commercial	SIC 8900: Services NEC					6	5.6									6	5.6
Commercial	SIC 9100: Government Fac.					13	41.1							1	0.1	14	41.2
Commercial	SIC 9200: Courts/Prisons	1	37.0			6	66.9									7	103.9
Commercial	SIC 9700: Military					9	155.7									9	155.7
	Total Commercial	15	73.0	0	0.0	469	1,586.8	0	0.0	2	52.6	0	0.0	29.0	5.2	515	1,717.6
	Grand Total	**18**	**123.0**	**8**	**396.7**	**669**	**7,692.3**	**5**	**11.7**	**15**	**524.0**	**18**	**231.6**	**43.0**	**150.6**	**776**	**9,129.8**

Table A-3
Existing CHP Operating in 2004 by Markets and Prime Mover

Sector	Application	Boiler/ Steam Turbine		Combined Cycle		Combustion Turbine		Reciprocating Engine		Fuel Cell		Microturbine		Other		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
Industrial	SIC 20: Food	6	88.8	9	912.9	13	318.2	17	31.2	1	0.2	1	0.1			47	1,351.4
Industrial	SIC 22:Textile Products							3	1.8							3	1.8
Industrial	SIC 24:Wood Products	18	262.1	1	49.5											19	311.6
Industrial	SIC 26: Paper	2	33.5	4	147.8	8	303.8	1	1.4							15	486.5
Industrial	SIC 27: Publishing					2	8.1	2	2.7							4	10.8
Industrial	SIC 28: Chemicals	6	261.3	1	28.0	3	95.2	5	6.0					1	0.5	16	391.0
Industrial	SIC 29: Petroleum Refining	2	47.5	5	780.3	9	383.6									16	1,211.4
Industrial	SIC 30: Rubber	1	27.0													1	27.0
Industrial	SIC 32: Stone, Clay, Glass	1	24.0			1	48.4	4	3.3			1	0.2			7	75.9
Industrial	SIC 33: Primary Metals			1	493.0			5	1.5							6	494.5
Industrial	SIC 34: Fabricated Metals							11	1.8			2	0.4			13	2.2
Industrial	SIC 35: Machinery							2	1.1							2	1.1
Industrial	SIC 36: Electrical Equipment							3	5.4							3	5.4
Industrial	SIC 37: Transportation Equip					2	11.9									2	11.9
Industrial	SIC 39: Misc Manufacturing					2	13.9	4	3.5					1	7.2	7	24.6
	Total Industrial	36	744.1	21	2,411.5	40	1,183.1	57	59.7	1	0.2	4	0.7	2.0	7.7	161	4,407.0
Other	SIC 9900: Unknown					1	8.0	5	0.9					1	0.6	7	9.6
Other	SIC 01: Agriculture	1	25.0	1	6.5			6	7.0							8	38.5
Other	SIC 13: Crude Oil	5	129.7	3	198.8	65	2,518.4	9	9.7			1	0.1			83	2,856.7
Other	SIC 14: Quarrying			1	55.4	1	45.0									2	100.4
	Total Other	6	154.7	5	260.7	67	2,571.4	20	17.7	0	0.0	1	0.1	1.0	0.6	100	3,005.2
Commercial	Storage					3	127.5	1	1.4							4	128.9
Commercial	SIC 4500: Air Transportation			1	30.0	1	8.0	1	0.5							3	38.5
Commercial	SIC 4800: Communications					1	2.3	1	1.4							2	3.7
Commercial	SIC 4939: Utilities	1	17.0	1	95.0	5	444.9	8	15.6			2	0.8			17	573.3
Commercial	SIC 4952: Wastewater Treatment					2	52.9	12	50.7	1	0.4	4	0.5			19	104.5
Commercial	SIC 4953: Solid Waste Facilites	1	35.6	1	29.7			1	2.0			1	1.3			4	68.6
Commercial	SIC 4961: District Energy							3	10.4							3	10.4
Commercial	SIC 5000: Wholesale/Retail							3	0.9							3	0.9
Commercial	SIC 5411: Food Stores							3	0.7							3	0.7
Commercial	SIC 5812: Restaurants							7	0.1							7	0.1
Commercial	SIC 6512: Comm. Building					4	12.9	23	13.0	2	0.6	3	0.8			32	27.3
Commercial	SIC 6513: Apartments							21	1.3			2	0.2			23	1.5
Commercial	SIC 7011: Hotels					1	1.1	45	8.0	1	0.2	5	0.6			52	9.8
Commercial	SIC 7200: Laundries							64	1.1							64	1.1
Commercial	SIC 7542: Carwashs											1	0.03			1	0.0
Commercial	SIC 7990: Amusement/ Rec.			1	49.8	1	0.1	41	3.8							43	53.7
Commercial	SIC 8051: Nursing Homes							16	4.9							16	4.9
Commercial	SIC 8060: Hospital/Healthcare	1	32.9	3	63.2	8	10.0	24	18.2	2	0.6	1	0.2			39	125.1
Commercial	SIC 8211: Schools							85	6.0			1	0.1			86	6.1
Commercial	SIC 8220: Colleges/Univ.			7	191.7	4	37.0	19	19.0	1	0.2	3	0.7			34	248.5
Commercial	SIC 8300: Comm Services							2	1.9							2	1.9
Commercial	SIC 8400: Zoos/Museums							1	1.4							1	1.4
Commercial	SIC 8800: Households							21	0.3							21	0.3
Commercial	SIC 8900: Services NEC					1	3.8	3	1.4	1	0.2			1	0.3	6	5.6
Commercial	SIC 9100: Government Fac.			2	30.5	1	0.5	9	9.9	1	0.2	1	0.1			14	41.2
Commercial	SIC 9200: Courts/Prisons			2	56.4	3	46.7	1	0.6	1	0.2					7	103.9
Commercial	SIC 9700: Military	1	3.0	5	142.9	1	7.2	2	2.6							9	155.7
	Total Commercial	4	88.5	23	689.2	36	754.8	417	177.0	10	2.6	24	5.2	1.0	0.3	515	1,717.6
	Grand Total	**46**	**987.3**	**49**	**3,361.4**	**143**	**4,509.3**	**494**	**254.3**	**11**	**2.8**	**29**	**6.0**	**4.0**	**8.6**	**776**	**9,129.8**

B

APPENDIX: TECHNICAL MARKET POTENTIAL DETAILED TABLES

Table B-1
Technical Market Potential for Traditional CHP in Existing Facilities

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
20	Food	1,183	177.5	279	209.3	206	515.0	13	113.8	1	51.5	1,682	1,067.0
22	Textiles	369	41.5	49	27.6	15	28.1	0	0.0	0	0.0	433	97.2
24	Lumber and Wood	543	16.3	82	12.3	30	15.0	2	12.0	0	0.0	657	55.6
25	Furniture	567	25.5	58	13.1	32	24.0	0	0.0	0	0.0	657	62.6
26	Paper	255	38.3	163	122.3	123	307.5	5	35.0	1	30.8	547	533.8
28	Chemicals	675	101.3	226	169.5	224	560.0	4	27.4	0	0.0	1,129	858.2
29	Petroleum Refining	189	28.4	31	23.3	12	30.0	3	42.7	2	170.6	237	294.8
30	Rubber/Misc Plastics	645	29.0	409	92.0	196	147.0	0	0.0	0	0.0	1,250	268.1
33	Primary Metals	321	12.0	105	19.7	119	74.4	1	5.6	1	28.0	547	139.7
34	Fabricated Metals	1,710	77.0	285	64.1	114	85.5	0	0.0	0	0.0	2,109	226.6
35	Machinery/Computer Equip	2,429	91.1	343	64.3	162	101.3	0	0.0	0	0.0	2,934	256.7
37	Trasportation Equip.	548	41.1	217	81.4	150	187.5	5	44.2	2	77.5	922	431.7
38	Instruments	892	66.9	295	110.6	176	220.0	1	6.6	0	0.0	1,364	404.1
39	Misc Manufacturing	622	23.3	48	9.0	27	16.9	1	5.0	0	0.0	698	54.2
6512	Commercial Buildings*	5,991	898.7	2,230	669.0	723	903.8	0	0.0	0	0.0	8,944	2,471.4
6513	Apartments	1,899	113.9	686	102.9	104	83.2	0	0.0	0	0.0	2,689	300.0
7542	Carwashes*	496	74.4	3	2.3	0	0.0	0	0.0	0	0.0	499	76.7
8412	Museums*	195	29.3	24	18.0	0	0.0	0	0.0	0	0.0	219	47.3
4222	Warehouses	129	19.4	152	114.0	8	20.0	0	0.0	0	0.0	289	153.4
4941	Water Treatment/Sanitary	267	40.1	141	105.8	110	275.0	1	12.5	0	0.0	519	433.3
7011	Hotels	3,370	379.1	661	371.8	270	506.3	12	112.5	0	0.0	4,313	1,369.7
7211	Laundries*	225	33.8	10	7.5	0	0.0	0	0.0	0	0.0	235	41.3
7991	Health Clubs*	648	97.2	130	97.5	2	5.0	0	0.0	0	0.0	780	199.7
7992	Golf/Country Clubs*	537	80.6	66	49.5	0	0.0	0	0.0	0	0.0	603	130.1
8051	Nursing Homes	1,056	158.4	376	282.0	16	40.0	0	0.0	0	0.0	1,448	480.4
8062	Hospitals	222	33.3	184	138.0	302	755.0	3	37.5	0	0.0	711	963.8
8211	Schools	3,016	226.2	650	243.8	65	81.3	7	43.8	0	0.0	3,738	595.0
8221	Colleges/Universities	268	40.2	231	173.3	116	290.0	71	887.5	8	600.0	694	1,991.0
9223	Prisons	67	10.1	77	57.8	49	122.5	15	187.5	0	0.0	208	377.8
	Total	**29,334**	**3,003.5**	**8,211**	**3,451.3**	**3,351**	**5,394.1**	**144**	**1,573.4**	**15**	**958.4**	**41,055**	**14,380.6**

* Low load factor markets

Table B-2
Traditional CHP Technical Market Potential for New Facilities Added between 2005-2020

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
20	Food	107	16.1	25	18.8	19	47.5	13	10.2	1	4.7	165	97.2
22	Textiles	111	12.5	15	8.4	4	7.5	0	0.0	0	0.0	130	28.4
24	Lumber and Wood	63	1.9	9	1.4	3	1.5	2	1.4	0	0.0	77	6.1
25	Furniture	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
26	Paper	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
28	Chemicals	729	109.4	244	183.0	242	605.0	4	29.3	0	0.0	1,219	926.6
29	Petroleum Refining	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
30	Rubber/Misc Plastics	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
33	Primary Metals	232	8.7	75	14.1	86	53.8	1	4.0	1	20.2	395	100.7
34	Fabricated Metals	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
35	Machinery/Computer Equip	59	2.2	9	1.7	3	1.9	0	0.0	0	0.0	71	5.8
37	Trasportation Equip.	591	44.3	233	87.4	162	202.5	5	47.7	2	83.6	993	465.6
38	Instruments	75	5.6	23	8.6	15	18.8	1	0.5	0	0.0	114	33.5
39	Misc Manufacturing	52	2.0	4	0.8	2	1.3	1	0.1	0	0.0	59	4.1
6512	Commercial Buildings*	3,276	491.4	1,219	365.7	396	495.0	0	0.0	0	0.0	4,891	1,352.1
6513	Apartments	967	58.0	348	52.2	54	43.2	0	0.0	0	0.0	1,369	153.4
7542	Carwashes*	28	4.2	0	0.0	0	0.0	0	0.0	0	0.0	28	4.2
8412	Museums*	73	11.0	9	6.8	0	0.0	0	0.0	0	0.0	82	17.7
4222	Warehouses	15	2.3	19	14.3	0	0.0	0	0.0	0	0.0	34	16.5
4941	Water Treatment/Sanitary	113	17.0	59	44.3	45	112.5	0	0.0	0	0.0	217	173.7
7011	Hotels	535	60.2	105	59.1	43	80.6	2	18.8	0	0.0	685	218.6
7211	Laundries*	12	1.8	0	0.0	0	0.0	0	0.0	0	0.0	12	1.8
7991	Health Clubs*	699	104.9	139	104.3	2	5.0	0	0.0	0	0.0	840	214.1
7992	Golf/Country Clubs*	579	86.9	71	53.3	0	0.0	0	0.0	0	0.0	650	140.1
8051	Nursing Homes	369	55.4	131	98.3	6	15.0	0	0.0	0	0.0	506	168.6
8062	Hospitals	78	11.7	65	48.8	106	265.0	0	0.0	0	0.0	249	325.5
8211	Schools	1,609	120.7	347	130.1	35	43.8	4	25.0	0	0.0	1,995	319.6
8221	Colleges/Universities	142	21.3	124	93.0	62	155.0	37	462.5	0	0.0	365	731.8
9223	Prisons	52	7.8	59	44.3	39	97.5	11	137.5	0	0.0	161	287.1
	Total	**10,566**	**1,256.9**	**3,332**	**1,438.1**	**1,324**	**2,252.2**	**81**	**737.0**	**4**	**108.4**	**15,307**	**5,792.6**

* Low load factor applications

Table B-3
Cooling CHP Technical Market Potential for Existing Facilities

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
43	Post Offices	76	11.4	0	0.0	0	0.0	0	0.0	0	0.0	76	11.4
4581	Airports	22	3.3	0	0.0	0	0.0	0	0.0	0	0.0	22	3.3
7832	Movie Theaters	203	30.5	0	0.0	0	0.0	0	0.0	0	0.0	203	30.5
52,53,56,5	Big Box Retail	1,033	155.0	716	214.8	255	318.8	0	0.0	0	0.0	2,004	688.5
5411	Food Sales	3,779	283.4	619	232.1	27	33.8	0	0.0	0	0.0	4,425	549.3
5812	Restaurants	6,431	482.3	94	35.3	36	45.0	0	0.0	0	0.0	6,561	562.6
7011	Hotels- Cooling*	3,370	505.5	661	495.8	270	675.0	12	150.0	0	0.0	4,313	1,826.3
8051	Nursing Homes- Cooling*	1,056	190.1	376	338.4	16	48.0	0	0.0	0	0.0	1,448	576.5
8062	Hospitals- Cooling*	222	40.0	184	165.6	302	906.0	3	45.0	0	0.0	711	1,156.6
	Grand Total	**16,192**	**1,701.4**	**2,650**	**1,481.9**	**906**	**2,026.5**	**15**	**195.0**	**0**	**0.0**	**19,763**	**5,404.8**

* Incremental applications that can be served by either traditional CHP or by CHP with cooling.

Table B-4
Cooling CHP Technical Market Potential for New Facilities Added Between 2005-2020

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
43	Post Offices	59	8.9	0	0.0	0	0.0	0	0.0	0	0.0	59	8.9
4581	Airports	12	1.8	0	0.0	0	0.0	0	0.0	0	0.0	12	1.8
7832	Movie Theaters	154	23.1	0	0.0	0	0.0	0	0.0	0	0.0	154	23.1
52,53,56,5	Big Box Retail	356	53.4	247	74.1	89	111.3	0	0.0	0	0.0	692	238.8
5411	Food Sales	1,307	98.0	213	79.9	8	10.0	0	0.0	0	0.0	1,528	187.9
5812	Restaurants	6,122	459.2	91	34.1	35	43.8	0	0.0	0	0.0	6,248	537.0
7011	Hotels- Cooling*	535	80.3	105	78.8	43	107.5	2	25.0	0	0.0	685	291.5
8051	Nursing Homes- Cooling*	369	66.4	131	117.9	6	18.0	0	0.0	0	0.0	506	202.3
8062	Hospitals- Cooling*	78	14.0	65	58.5	106	318.0	0	0.0	0	0.0	249	390.5
	Grand Total	**8,992**	**805.0**	**852**	**443.3**	**287**	**608.5**	**2**	**25.0**	**0**	**0.0**	**10,133**	**1,881.8**

Incremental applications that can be served by either traditional CHP or by CHP with cooling.

Table B-5
Traditional CHP Technical Market Potential by Region and Utility

Region/Utility		Existing Facilities						New Facilities 2005-2020					
Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	1,130	1,296	1,975	596	285	5,283	463	526	801	286	25	2,100
	SMUD	87	111	154	30	0	383	39	50	63	13	0	165
	Other North	13	13	14	0	0	39	5	6	8	0	0	18
North Total		1,230	1,420	2,143	626	285	5,705	507	582	872	299	25	2,284
South	LADWP	265	306	525	154	75	1,325	111	127	218	45	0	501
	SCE	1,223	1,377	2,207	668	523	5,998	516	573	934	322	84	2,429
	SDG&E	242	302	447	83	75	1,149	104	139	200	46	0	490
	Other South	43	46	72	43	0	203	19	17	28	25	0	89
South Total		1,774	2,031	3,251	947	673	8,675	750	857	1,380	438	84	3,509
Grand Total		3,003	3,451	5,394	1,573	958	14,381	1,257	1,438	2,252	737	108	5,793

Table B-6
Cooling CHP Technical Market Potential by Region and Utility

Region/Utility		Existing Facilities						New Facilities 2005-2020					
Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	697	595	786	65	0	2,143	309	172	234	13	0	728
	SMUD	52	54	62	0	0	168	27	17	20	0	0	64
	Other North	11	9	7	0	0	27	3	2	4	0	0	9
North Total		760	658	855	65	0	2,338	339	191	259	13	0	801
South	LADWP	129	114	187	25	0	455	66	36	55	0	0	157
	SCE	639	540	761	90	0	2,029	315	168	233	13	0	728
	SDG&E	150	154	193	15	0	512	74	44	54	0	0	171
	Other South	24	16	32	0	0	72	11	5	9	0	0	24
South Total		942	824	1,172	130	0	3,067	466	252	350	13	0	1,080
Grand Total		1,701	1,482	2,027	195	0	5,405	805	443	609	25	0	1,882

C

APPENDIX: SECTORAL GROWTH RATE ASSUMPTIONS

Table C-1
Average Annual Growth Rates Assumed for New Facility Growth (Based on Average Real Sectoral Growth Rates 1992-1997)

SICs	Application	Average Annual Growth Rate
20	Food	0.58%
22	Textiles	1.77%
24	Lumber and Wood	0.72%
25	Furniture	0.00%
26	Paper	0.00%
28	Chemicals	5.00%
29	Petroleum Refining	0.00%
30	Rubber/Misc Plastics	0.00%
33	Primary Metals	3.68%
34	Fabricated Metals	0.00%
35	Machinery/Computer Equip	0.16%
37	Trasportation Equip.	5.00%
38	Instruments	0.53%
39	Misc Manufacturing	0.53%
43	Post Offices	3.87%
4581	Airports	2.95%
6512	Commercial Buildings	2.95%
6513	Apartments	2.78%
7542	Carwashes	0.37%
7832	Movie Theaters	3.85%
8412	Museums	2.16%
4222, 5142	Warehouses	0.78%
4941, 4952	Water Treatment/Sanitary	2.37%
52,53,56,57	Big Box Retail	2.00%
5411, 5421, 5451, 5461, 5499	Food Sales	2.00%
5812, 00, 01, 03, 05, 07, 08	Restaurants	4.56%
7011, 7041	Hotels	0.99%
7011, 7042	Hotels- Cooling	0.99%
7211, 7213, 7218	Laundries	0.37%
7991, 00, 01	Health Clubs	5.00%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	5.00%
8051, 8052, 8059	Nursing Homes	2.02%
8051, 8052, 8060	Nursing Homes- Cooling	2.02%
8062, 8063, 8069	Hospitals	2.02%
8062, 8063, 8070	Hospitals- Cooling	2.02%
8211, 8243, 8249, 8299	Schools	2.89%
8221, 8222	Colleges/Universities	2.89%
23, 9211 (Courts), 9224 (firehous	Prisons	3.87%

Note: Maximum Sector Growth Capped at 5% per year; zero growth assumed for declining sectors.

D
APPENDIX: ENERGY PRICE FORECASTS

The estimation of retail electric rates is based on the following sources:

- 2003 IEPR end-use forecast prices (medium commercial and industrial), for SDG&E, SCE, LADWP, PG&E, SMUD
- Current tariffs for customer rates and for customer DG rates (standby rates)
- SCE – TOU-8 (Standby: Schedule S)
- PG&E – E-20 (Standby: Schedule S)
- SDG&E – AL-TOU (Standby: AL-TOU-DER)
- LADWP – A-3 (Standby; Schedule CG-3)
- SMUD – GS-TOU1 (Standby: Rule 19)
- Natural gas EG price track for escalating the generation component of rates (based on a high efficiency natural gas combined cycle power plant, power rates increase by 0.7% for every 1% increase in gas rates.)

Based on the inputs described above, the electric rates are calculated as follows:

- For each utility, the rate structure is used to estimate average costs for continuous use, and the avoided cost for a continuous CHP system are estimated. To derive this avoided average cost, it was assumed that the energy costs are avoided up to the load factor of the CHP system (assumed to be 92%). It was assumed that demand charges would be avoided 10 months out of 12 (in 2 months the CHP system was assumed to go down on peak), and that facilities demand charges (which are ratcheted at 50% of the previous 11 month maximum) would always be pinned at the 50% ratchet.
- These costs are calculated for secondary, primary, and transmission voltages. It is assumed that the secondary voltage applies to 500kW to 1 MW customer class, the primary applies to 1 MW to 20 MW, and that transmission voltages apply to customers over 20 MW.
- Commercial rates are estimated using the 2005 electric prices forecast by Energy Commission (2003 IEPR) for medium commercial customers and reducing by the ratio of avoided costs to total costs for the secondary industrial customer.
- For the IOUs, these costs are disaggregated by generation and other delivery costs. The forecast of rates is based on the assumption that delivery (non-generation charges) are fixed for 5 years (declining real costs using the 2003 IEPR estimate of the GSP price deflator) and then are constant in real terms. The generation costs vary as described above based on changes in the EEG gas price forecast.

- The two largest municipal utilities do not provide a breakdown of generation and non generation costs. The calculated 2005 retail rates are assumed to be constant in real terms for the 15 year forecast period.
- Standby costs were estimated for each size and utility. This is a complicated area. There are currently exemptions for CHP for certain standby charges and for some utilities, the customer does not have to go onto a separate standby rate, but instead stays on their existing rate structure. The absence of a standby rate does not necessarily mean lower costs for the CHP customer because peak period demand charges can be triggered by failure of the unit during peak periods. These peak period demand charges are typically higher than a standby reservation charge. CHP customers are required to pay certain exit fees. All CHP customers must pay the public purpose program surcharge and the nuclear decommissioning surcharge on their departing load. Customers with CHP above 1 MW must also pay the DWR bond charge; customers below 1 MW are exempt from this charge. All qualifying CHP systems are exempt from paying the CTC on departing load.
- LADWP has a separate tariff for customers with distributed generation resources. This rate creates a higher penalty than those customers that just pay the departing load surcharges.

The electric rate assumptions are shown in **Tables D-1** through **D-3**.

Natural gas pricing is based primarily on the high wellhead gas price scenario in the 2003 *Natural Gas Market Assessment* that was undertaken in support of the 2003 Integrated Energy Policy Report Proceeding.[19] The first four years of the forecast (2005-2008) are based on NYMEX Henry Hub gas futures contracts. Retail gas price mark-ups and regional were derived from the Energy Commission study. It was assumed that in the Northern California, the Electric generation/CHP, industrial, and commercial retail rate adders to the border price are $0.25, $0.40, and $1.00 respectively. It is assumed that retail prices are $0.45/MMBtu higher in the Southern California. **Table D-4** summarizes the gas pricing assumptions. For the analysis, the forecast years are 2010, 2015, and 2020.

These prices are adjusted by the Utility Users Tax (UUT) which is a tax on utility services that is applied at the municipal level. The values assumed for this analysis are PG&E, SCE, and SMUD (7.5%); LADWP (10%); SDG&E (3%), and other North and South region utilities (5%). San Diego doesn't have a UUT *per se,* but charges San Diego customers for franchise fees paid to municipalities.

[19] Leon Brathwaite, et al., *Natural Gas Market Assessment*, California Energy Commission, Report 100-03-006, August 2003.

Table D-1
High Load Factor Avoided Power Costs and Standby Charges

Utility	2005	2010	2015	2020	Standby
Medium Commercial					
LADWP	$0.0974	$0.0974	$0.0974	$0.0974	$0.0206
PG&E	$0.1179	$0.1068	$0.1095	$0.1113	$0.0048
SCE	$0.1072	$0.0973	$0.1003	$0.1023	$0.0037
SDG&E	$0.1066	$0.0968	$0.0998	$0.1018	$0.0061
SMUD	$0.0980	$0.0980	$0.0980	$0.0980	$0.0076
Industrial -- Secondary					
LADWP	$0.0876	$0.0876	$0.0876	$0.0876	$0.0187
PG&E	$0.1048	$0.0950	$0.0978	$0.0996	$0.0048
SCE	$0.0943	$0.0857	$0.0885	$0.0904	$0.0037
SDG&E	$0.0943	$0.0857	$0.0885	$0.0904	$0.0061
SMUD	$0.0869	$0.0869	$0.0869	$0.0869	$0.0076
Industrial -- Primary					
LADWP	$0.0842	$0.0842	$0.0842	$0.0842	$0.0187
PG&E	$0.0950	$0.0863	$0.0892	$0.0910	$0.0092
SCE	$0.0940	$0.0855	$0.0884	$0.0902	$0.0083
SDG&E	$0.0940	$0.0855	$0.0884	$0.0902	$0.0109
SMUD	$0.0790	$0.0790	$0.0790	$0.0790	$0.0060
Industrial -- Subtransmission					
LADWP	$0.0810	$0.0810	$0.0810	$0.0810	$0.0180
PG&E	$0.0827	$0.0752	$0.0778	$0.0796	$0.0084
SCE	$0.0789	$0.0718	$0.0745	$0.0762	$0.0073
SDG&E	$0.0789	$0.0718	$0.0745	$0.0762	$0.0109
SMUD	$0.0759	$0.0759	$0.0759	$0.0759	$0.0030

Table D-2
Low Load Factor Avoided Power Costs and Standby Charges (4500 Hours/year)

Utility	2005	2010	2015	2020	Standby
Medium Commercial					
LADWP	$0.1020	$0.1020	$0.1020	$0.1020	$0.0501
PG&E	$0.1446	$0.1308	$0.1341	$0.1362	$0.0048
SCE	$0.1358	$0.1232	$0.1269	$0.1292	$0.0037
SDG&E	$0.1276	$0.1158	$0.1192	$0.1214	$0.0061
SMUD	$0.1141	$0.1141	$0.1141	$0.1141	$0.0148
Industrial -- Secondary					
LADWP	$0.0917	$0.0917	$0.0917	$0.0917	$0.0456
PG&E	$0.1284	$0.1164	$0.1198	$0.1219	$0.0048
SCE	$0.1194	$0.1085	$0.1120	$0.1142	$0.0037
SDG&E	$0.1128	$0.1025	$0.1057	$0.1078	$0.0061
SMUD	$0.1012	$0.1012	$0.1012	$0.1012	$0.0148
Industrial -- Primary					
LADWP	$0.0917	$0.0917	$0.0917	$0.0917	$0.0456
PG&E	$0.1133	$0.1029	$0.1062	$0.1084	$0.0092
SCE	$0.1193	$0.1083	$0.1118	$0.1141	$0.0083
SDG&E	$0.1122	$0.1019	$0.1052	$0.1073	$0.0109
SMUD	$0.0919	$0.0919	$0.0919	$0.0919	$0.0117
Industrial -- Subtransmission					
LADWP	$0.0879	$0.0879	$0.0879	$0.0879	$0.0456
PG&E	$0.0945	$0.0859	$0.0889	$0.0909	$0.0084
SCE	$0.0951	$0.0865	$0.0896	$0.0916	$0.0073
SDG&E	$0.0968	$0.0882	$0.0914	$0.0935	$0.0109
SMUD	$0.0871	$0.0871	$0.0871	$0.0871	$0.0058

Table D-3
Peak Cooling Load Avoided Power Costs

Utility	2005	2010	2015	2020	Standby
Medium Commercial					
LADWP	$0.1806	$0.1643	$0.1701	$0.1738	n.a.
PG&E	$0.2248	$0.2031	$0.2078	$0.2108	n.a.
SCE	$0.2199	$0.1991	$0.2043	$0.2077	n.a.
SDG&E	$0.1662	$0.1502	$0.1538	$0.1560	n.a.
SMUD	$0.1214	$0.1214	$0.1214	$0.1214	n.a.
Industrial -- Secondary					
LADWP	$0.1625	$0.1478	$0.1530	$0.1564	n.a.
PG&E	$0.1997	$0.1808	$0.1856	$0.1887	n.a.
SCE	$0.1933	$0.1753	$0.1804	$0.1837	n.a.
SDG&E	$0.1470	$0.1330	$0.1364	$0.1386	n.a.
SMUD	$0.1077	$0.1077	$0.1077	$0.1077	n.a.
Industrial -- Primary					
LADWP	$0.1625	$0.1478	$0.1530	$0.1564	n.a.
PG&E	$0.1691	$0.1534	$0.1582	$0.1612	n.a.
SCE	$0.1942	$0.1760	$0.1811	$0.1844	n.a.
SDG&E	$0.1456	$0.1318	$0.1352	$0.1373	n.a.
SMUD	$0.0937	$0.0937	$0.0937	$0.0937	n.a.
Industrial -- Subtransmission					
LADWP	$0.1536	$0.1397	$0.1445	$0.1477	n.a.
PG&E	$0.1259	$0.1144	$0.1183	$0.1207	n.a.
SCE	$0.1430	$0.1299	$0.1341	$0.1369	n.a.
SDG&E	$0.1094	$0.0994	$0.1028	$0.1050	n.a.
SMUD	$0.0889	$0.0889	$0.0889	$0.0889	n.a.

Table D-4
Electric and Natural Gas Price Assumptions ($2005/MMBtu)

		Wholesale Energy	Fuel Costs 2005 $/MMBtu			
		Market Price $/MWh	EG Case	North Cogen / EG	Com	Ind
2005	Level (chp owner)	$0.065	$6.512	$6.062	$6.812	$6.212
	Level (utility)	$0.066	$6.607	$6.157	$6.907	$6.307
	Level (society) *	$0.066	$6.636	$5.936	$5.936	$5.936
2010	Level (chp owner)	$0.067	$6.724	$6.274	$7.024	$6.424
	Level (utility)	$0.068	$6.846	$6.396	$7.146	$6.546
	Level (society) *	$0.068	$6.908	$6.208	$6.208	$6.208
2015	Level (chp owner)	$0.070	$7.085	$6.635	$7.385	$6.785
	Level (utility)	$0.071	$7.206	$6.756	$7.506	$6.906
	Level (society) *	$0.071	$7.264	$6.814	$6.814	$6.814
	2005	$ 0.067	7.19	6.74	7.49	6.89
	2006	$ 0.068	6.72	6.27	7.02	6.42
	2007	$ 0.066	6.20	5.75	6.5	5.9
	2008	$ 0.059	5.76	5.31	6.06	5.46
	2009	$ 0.063	6.26	5.81	6.56	5.96
	2010	$ 0.064	6.39	5.94	6.69	6.09
	2011	$ 0.065	6.49	6.04	6.79	6.19
	2012	$ 0.066	6.59	6.14	6.89	6.29
	2013	$ 0.067	6.69	6.24	6.99	6.39
	2014	$ 0.067	6.77	6.32	7.07	6.47
	2015	$ 0.068	6.84	6.39	7.14	6.54
	2016	$ 0.068	6.90	6.45	7.2	6.6
	2017	$ 0.069	6.97	6.52	7.27	6.67
	2018	$ 0.069	7.02	6.57	7.32	6.72
	2019	$ 0.070	7.08	6.63	7.38	6.78
	2020	$ 0.070	7.13	6.68	7.43	6.83

E
APPENDIX: TECHNOLOGY COST AND PERFORMANCE ASSUMPTIONS

Introduction

A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100 – 40,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. Cost and performance estimates for the CHP systems were based on a series of peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory[20] and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory.[21] Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI.[22]

To these basic cost and performance assumptions were added cost multipliers that reflected the difference between the cost of construction in California versus the U.S. average and an early market/site specific cost multiplier. This factor was based on a review of the difference between the basic cost estimates and a number of projects proposed for funding under the Small Generator Incentive Program (SGIP.) These factors were assumed to reflect the added costs of engineering and site specific improvements that are typical in today's projects.

Basic Technology Cost and Performance

Tables E-1 through E-4 include data for a range of system sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2005 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010 and 2020 reflect current technology development paths assuming planned government and industry R&D funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control. NOx emissions are presented with and without a CHP thermal credit (using

[20] "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL, November 2003, http://www.osti.gov/bridge
[21] "Clean Distributed Generation Performance and Cost Analysis", DE Solutions for ORNL. April 2004.
[22] "Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators", EPRI, January 2005.

the ARB total output approach). NOx emissions levels that are at or below the proposed ARB 2007 DG emissions standards of 0.07 lbx/MWh are highlighted in the tables. Which systems (with aftertreatment, without aftertreatment, with or without CHP thermal credit, etc.) are applicable in any size category or region is a function of the specific emissions requirements assumptions for each scenario or sensitivity run.

Reciprocating Engines

Table E-1 summarizes the performance and emissions assumptions used for reciprocating engines ranging from 100 to 5,000 kW capacity. The 100 kW and 300 kW systems were assumed to be rich burn engines with three way catalyst aftertreatment. NOx, CO and VOC emissions are presented in the tables for these engines post exhaust treatment. The larger engines were assumed to be lean burn engines. Emissions estimates are presented with and without aftertreatment (assumed to be SCR/CO oxidation). None of the reciprocating engine systems can meet the proposed 2007 ARB DG NOx standard of 0.07 lb/MWh even with aftertreatment. The 2010 and 2020 systems can meet the standard using aftertreatment and utilizing the CHP thermal credit.

Gas Turbines

Table E-2 summarizes the performance and emissions assumptions used for combustion turbines ranging from 1 to 40 MW capacity. The 1 MW turbine assumes steam injection combustion in 2005. This turbine is unable to meet the 0.07 lb/MWh NOx standard in 2005 even with aftertreatment, but can meet the standard in 2010 and 2020 with aftertreatment and the CHP thermal credit. The larger turbines all are based on state of the art and commercially available DLN combustors. Emissions estimates are presented with and without aftertreatment (assumed to be SCR/CO oxidation). All of the larger turbines require SCR and the CHP thermal credit to meet the 0.07 lb/MWh standard in 2005 and 2010.

Microturbines

Table E-3 summarizes the performance and emissions assumptions for microturbines ranging from 100 to 500 kW capacity. The emerging 500 kW unit is assumed to be available starting in 2010. The 100 kW system is the only unit that can meet the proposed 2007 0.07 lb/MWh NOx standard. The larger systems can meet the standard in 2010 with aftertreatment. However, aftertreatment technologies for systems of this size prohibitively. The 250 and 500 kW systems can meet the 0.07 lb/MWh standard in 2020 without aftertreatment and utilizing the CHP thermal credit. tems because of cost considerations.

Fuel Cells

Table E-4 summarizes the performance and emissions assumptions used for fuel cell systems ranging from 150 kW to 2 MW. The 150 kW unit is based on emerging PEMFC technology. The 250 kW unit is based on a commercially available MCFC unit in 2005 transitioning to emerging SOFC technology in 2010. The 2 MW unit is based on MCFC technology. Due to their very low emissions, fuel cell systems do not require any emissions control devices to meet current and projected regulations.

Emissions Requirements

Table E-5 presents gas turbine and gas-fired reciprocating engine NOx emissions requirements for three of the largest air districts in California. On-site generating units below 50 horsepower in size are subject to the statewide ARB DG standards that currently require 9 ppm NOx limits for gas turbines and 0.15 gm/bhp-hr for engines (these equate to 0.5 lbs/MWh). As shown in the table, current NOx limits for systems between 50 hp and 50 MW vary by size and district, but generally require gas turbines below 2 to 3 MW to meet 9 ppm, and larger turbines to meet 2.5 ppm. Engines are currently required to meet 0.15 gm/bhp-hr across the districts. Base case assumptions for the analysis assumed that the proposed 2007 ARB DG NOx standards of 0.07 lbs/MWh would be implemented statewide for units below 50 hp. For units between 50 hp and 50 MW, the base case assumed that the stricter 0.07 lbs/MWh standard would be adopted starting in 2005 in the Southern California segment (reflecting the stated intentions of the South Coast Air Quality District). The NOx standards for this size range in the Northern California segment would remain as currently required (i.e., 0.15 lbs/MWh for engines and 9 to 2.5 ppm for turbines).

Construction Costs and Early Market Cost Multipliers

The cost estimates shown in the tables reflect a basic installation in a mature market. The costs for this study were adjusted to reflect higher construction costs in California and also to reflect the added costs for installations that are representative of today's market.

The estimates of installed capital costs for each of the technologies shown in the attachment are assumed to be based on national average costs, mature market assumptions on engineering, planning, etc., and without any site specific extras that are common, particularly for applications in existing facilities. To adjust these cost estimates we first adjusted for regional construction costs (based on Means estimates for power plant construction) These construction cost adders are as follows:

Region	Utility	Construction Cost Markup
North	PG&E	123.4%
	SMUD	110.9%
	Other North	110.9%
North Total		
South	LADWP	106.3%
	SCE	106.3%
	SDG&E	104.6%
	Other South	106.3%

In addition, a comparison was made to the capital costs reported in applications under the SGIP program and cost multipliers were developed to reflect early market extra costs which gradually disappear over the forecast period, and a small allowance for site specific extras (10% at the small end and 5% for large projects) that are applied in all time periods. There are no early market costs assumed for projects larger than 5 MW, just site specific costs at 5% of total capital.

The early market cost multipliers (that include the site specific costs as well) range from 8-28% for small reciprocating engines, 17% for microturbines, 15-25% for fuel cells, and 15% for small gas turbines. These early market cost factors are assumed to decline over time to a base value in 2020 of 110% for small systems to 105% for gas turbines. These minimum values are assumed to reflect site specific factors not included in the base capital cost estimates.

Table E-1
Reciprocating Engine Cost and Performance Assumptions

Size and Type	Characterization	2005	2010	2020
100 kW Rich Burn	Capacity, kW	100	100	100
	Installed Costs, $/kW	1,550	1,350	1,100
w/three way catalyst	Heat Rate, Btu/kWh	11,500	10,830	10,500
	Electric Efficiency, %	29.7%	31.5%	32.5%
	Power to Heat Ratio	0.61	0.67	0.7
	Thermal Output, Btu/kWh	5593	5093	4874
	O&M Costs, $/kWh	0.018	0.013	0.012
	NOx Emissions, lbs/MWh (no AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (w/ AT)	0.5	0.15	0.15
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	0.19	0.06	0.06
	AT Cost, $/kW	N/A	N/A	N/A
300 kW Rich Burn	Capacity, kW	300	300	300
	Installed Costs, $/kW	1,250	1,150	1,050
	Heat Rate, Btu/kWh	11,500	10,830	10,500
	Electric Efficiency, %	29.7%	31.5%	32.5%
	Power to Heat Ratio	0.61	0.67	0.7
	Thermal Output, Btu/kWh	5593	5093	4874
	O&M Costs, $/kWh	0.013	0.012	0.01
	NOx Emissions, gm/bhphr	1.5	1	0.5
	NOx Emissions, lbs/MWh (no AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (no AT; w/CHP)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (w/ AT)	0.5	0.15	0.15
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	0.19	0.06	0.06
	AT Cost, $/kW	50	50	45
1,000 kW Lean Burn	Capacity, kW	1000	1000	1000
	Installed Costs, $/kW	1,200	1,100	950
	Heat Rate, Btu/kWh	10,350	9,100	8,638
	Electric Efficiency, %	33.0%	37.5%	39.5%
	Power to Heat Ratio	0.92	1.07	1.18
	Thermal Output, Btu/kWh	3709	3189	2892
	O&M Costs, $/kWh	0.012	0.01	0.009
	NOx Emissions, gm/bhphr	1	0.4	0.25
	NOx Emissions, lbs/MWh (no AT)	3.1	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	1.49	0.64	0.42
	NOx Emissions, lbs/MWh (w/ AT)	0.31	0.124	0.09
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	0.15	0.06	0.05
	AT Cost, $/kW	300	225	150
3,000 kW Lean Burn	Capacity, kW	3000	3000	3000
	Installed Costs, $/kW	950	925	875
	Heat Rate, Btu/kWh	9,700	8,750	8,325
	Electric Efficiency, %	35.2%	39.0%	41.0%
	Power to Heat Ratio	1.04	1.07	1.18
	Thermal Output, Btu/kWh	3281	3189	2892
	O&M Costs, $/kWh	0.0085	0.0083	0.008
	NOx Emissions, gm/bhphr	0.7	0.4	0.25
	NOx Emissions, lbs/MWh (no AT)	2.17	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	1.11	0.64	0.42
	NOx Emissions, lbs/MWh (w/ AT)	0.217	0.124	0.09
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	0.11	0.06	0.05
	AT Cost, $/kW	275	175	110
5,000 kW Lean Burn	Capacity, kW	5000	5000	5000
	Installed Costs, $/kW	925	900	850
	Heat Rate, Btu/kWh	9,213	8,325	7,935
	Electric Efficiency, %	37.0%	41.0%	43.0%
	Power to Heat Ratio	1.02	1.22	1.31
	Thermal Output, Btu/kWh	3345	2797	2605
	O&M Costs, $/kWh	0.008	0.008	0.008
	NOx Emissions, gm/bhphr	0.5	0.4	0.25
	NOx Emissions, lbs/MWh (no AT)	1.55	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.78	0.68	0.44
	NOx Emissions, lbs/MWh (w/ AT)	0.155	0.124	0.09
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	0.08	0.07	0.05
	AT Cost, $/kW	250	150	100

Table E-2
Gas Turbine Cost and Performance Assumptions

Size and Type	Characterization	2005	2010	2020
1 MW Gas Turbine	Capacity, MW	1	1	1
	Installed Costs, $/kW	1,900	1,500	1,300
	Heat Rate, Btu/kWh	15,580	14,500	13,500
	Electric Efficiency, %	21.9%	23.5%	25.3%
	Power to Heat Ratio	0.51	0.61	0.7
	Thermal Output, Btu/kWh	6690	5593	4874
	O&M Costs, $/kWh	0.01	0.013	0.012
	NOx Emissions, ppm	42.0	15.0	9.0
	NOx Emissions, lbs/MWh (no AT)	2.2	0.7	0.4
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.74	0.27	0.16
	NOx Emissions, lbs/MWh (w/ AT)	0.22	0.07	0.04
	AT Cost, $/kW	300	250	150
3 MW Gas Turbine	Capacity, MW	5	5	5
	Installed Costs, $/kW	1,300	1,200	1,000
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Power to Heat Ratio	0.68	0.76	0.84
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.68	0.38	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.28	0.16	0.09
	NOx Emissions, lbs/MWh (w/ AT)	0.068	0.038	0.02
	AT Cost, $/kW	210	175	150
5 MW Gas Turbine	Capacity, MW	5	5	5
	Installed Costs, $/kW	1,100	1,000	950
	Heat Rate, Btu/kWh	12,590	11,375	10,500
	Electric Efficiency, %	27.1%	30.0%	32.5%
	Power to Heat Ratio	0.68	0.76	0.84
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.68	0.38	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.28	0.16	0.09
	NOx Emissions, lbs/MWh (w/ AT)	0.068	0.038	0.02
	AT Cost, $/kW	210	175	150
10 MW Gas Turbine	Capacity, MW	10	10	10
	Installed Costs, $/kW	965	950	850
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Power to Heat Ratio	0.73	0.84	0.94
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.67	0.37	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.28	0.17	0.10
	NOx Emissions, lbs/MWh (w/ AT)	0.067	0.037	0.02
	AT Cost, $/kW	140	125	100
25 MW Gas Turbine	Capacity, MW	25	25	25
	Installed Costs, $/kW	800	755	725
	Heat Rate, Btu/kWh	9,945	9,225	8,865
	Electric Efficiency, %	34.3%	37.0%	38.5%
	Power to Heat Ratio	0.95	1.04	1.1
	Thermal Output, Btu/kWh	3592	3281	3102
	O&M Costs, $/kWh	0.005	0.005	0.004
	NOx Emissions, ppm	15.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.6	0.2	0.1
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.29	0.10	0.05
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.02	0.01
	AT Cost, $/kW	100	80	50
40 MW Gas Turbine	Capacity, MW	40	40	40
	Installed Costs, $/kW	700	680	660
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Power to Heat Ratio	1.07	1.13	1.18
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, ppm	15.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.55	0.2	0.1
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.28	0.11	0.05
	NOx Emissions, lbs/MWh (w/ AT)	0.055	0.02	0.01
	AT Cost, $/kW	90	75	40

Table E-3
Microturbine Cost and Performance Assumptions

Size and Type	Characterization	2005	2010	2020
70-100 kW	Capacity, kW	70	70	70
	Installed Costs, $/kW	2,200	1,800	1,400
	Heat Rate, Btu/kWh	13,500	12,500	11,375
	Electric Efficiency, %	25.3%	27.3%	30.0%
	Power to Heat Ratio	0.7	0.9	1.1
	Thermal Output, Btu/kWh	4874	3791	3102
	O&M Costs, $/kWh	0.017	0.016	0.012
	NOx Emissions, ppm	3.0	3.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.15	0.14	0.13
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.06	0.07	0.07
	NOx Emissions, lbs/MWh (w/ AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	AT Cost, $/kW	N/A	N/A	N/A
250 kW	Capacity, kW	250	250	250
	Installed Costs, $/kW	2,000	1,600	1,200
	Heat Rate, Btu/kWh	11,850	11,750	10,825
	Electric Efficiency, %	28.8%	29.0%	31.5%
	Power to Heat Ratio	0.94	1	1.3
	Thermal Output, Btu/kWh	3630	3412	2625
	O&M Costs, $/kWh	0.016	0.015	0.012
	NOx Emissions, ppm	9.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.43	0.24	0.13
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.21	0.12	0.07
	NOx Emissions, lbs/MWh (w/ AT)	0.04	0.02	0.01
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	AT Cost, $/kW	500	200	90
500 kW	Capacity, kW	-	500	500
	Installed Costs, $/kW	-	1,150	900
	Heat Rate, Btu/kWh	-	10,350	9,750
	Electric Efficiency, %	-	33.0%	35.0%
	Power to Heat Ratio	-	1.3	1.38
	Thermal Output, Btu/kWh	-	2625	2472
	O&M Costs, $/kWh	-	0.015	0.012
	NOx Emissions, ppm	-	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	-	0.2	0.11
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-	0.11	0.06
	NOx Emissions, lbs/MWh (w/ AT)	-	0.02	0.011
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	-	N/A	N/A
	AT Cost, $/kW	-	200	90

Table E-4
Fuel Cell Cost and Performance Assumptions

Size and Type	Characterization	2005	2010	2020
150 kW PEMFC	Capacity, kW	150	150	150
	Installed Costs, $/kW	3,800	3,600	2,700
	Heat Rate, Btu/kWh	9,750	9,480	8,980
	Electric Efficiency, %	35.0%	36.0%	38.0%
	Power to Heat Ratio	0.95	0.98	1.04
	Thermal Output, Btu/kWh	3592	3482	3281
	O&M Costs, $/kWh	0.023	0.017	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.10	0.07	0.05
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.05	0.03	0.03
250 kW MCFC/SOFC	Capacity, kW	250	250	250
	Installed Costs, $/kW	5,000	3,200	2,500
MCFC 2005	Heat Rate, Btu/kWh	7,930	7,125	6,920
	Electric Efficiency, %	43.0%	47.9%	49.3%
SOFC 2010	Power to Heat Ratio	1.95	1.98	2.13
	Thermal Output, Btu/kWh	1750	1723	1602
	O&M Costs, $/kWh	0.032	0.02	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.06	0.05	0.04
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.04	0.03	0.03
	NOx Emissions, lbs/MWh (w/ AT)			
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)			
	AT Cost, $/kW	na	na	na
2 MW MCFC	Capacity, kW	2,000	2000	2000
	Installed Costs, $/kW	3,250	2,800	2,200
	Heat Rate, Btu/kWh	7,420	7,110	6,820
	Electric Efficiency, %	46.0%	48.0%	50.0%
	Power to Heat Ratio	1.92	2	2.27
	Thermal Output, Btu/kWh	1777	1706	1503
	O&M Costs, $/kWh	0.033	0.019	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.05	0.05	0.04
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.03	0.03	0.03
	NOx Emissions, lbs/MWh (w/ AT)			
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)			
	AT Cost, $/kW			

Table E-5
Emissions Requirements for Three Largest Air Quality Districts

Technology	Exempt (1298) (< 50 hp)	BACT (up to 50 MW)			> 50 MW
		Bay Area	South Coast	San Joaquin	
2003 Standards					
Gas Turbines	0.5 lbs/MWh (9 ppm)	9 ppm, < 2 MW 5 ppm, 2 to 40 MW	9 ppm, < 3 MW 2.5 ppm, 2 to 50 MW	9 ppm, < 3 MW 2.5 ppm, 2 to 50 MW	2.5 ppm
Recip Engines	0.5 lbs/MWh (0.15 gm/bhphr)	0.15 gm/bhphr	0.15 gm/bhphr	0.15 gm/bhphr	N/A
2007 Standards					
Gas Turbines	0.07 lbs/MWh (1.5 ppm)	9 ppm, < 2 MW 5 ppm, 2 to 40 MW	0.07 lbs/MWh	9 ppm, < 3 MW 2.5 ppm, 2 to 50 MW	2.5 ppm
Recip Engines	0.07 lbs/MWh (0.022 gm/bhphr)	0.15 gm/bhphr	0.07 lbs/MWh	0.15 gm/bhphr	N/A

F
APPENDIX: MARKET PENETRATION MODEL DESCRIPTION

Figure F-1 provides a graphical depiction of the market penetration analytical framework used to estimate CHP market penetration. There are four basic components to this framework:

1. Technical Market Potential – The output of this analysis is an estimate of the technically suitable CHP applications by size and by industry. This estimate is derived from the screening of market databases based on application and size characteristics that are used to estimate groups of facilities with appropriate electric and thermal load characteristics.
2. Energy Price Estimation – Present and future fuel prices are estimated to provide inputs into the CHP net power cost calculator.
3. Technology Characterization – For each size range, a set of applicable CHP technologies is selected for evaluation. These technologies are characterized in terms of their capital cost, heat rate, non-fuel operating and maintenance costs, and available thermal energy for process use on-site
4. Market Deployment – Within each market size, the competition among applicable technologies is evaluated. Based on this competition, the economic market potential is estimated and shared among competing CHP technologies. The rate of market penetration by technology is then estimated using a market diffusion model.

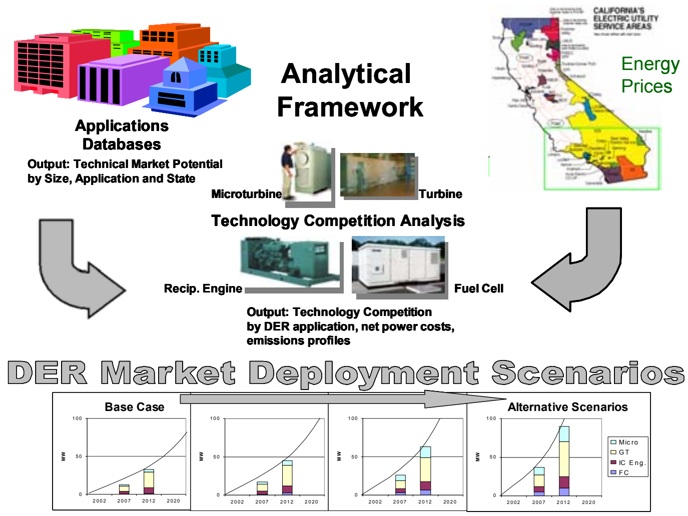


Figure F-1
Market Penetration Model

The technical potential is grouped into five separate categories (high load and low load factor traditional CHP, high and low load factor CHP with cooling, and large CHP for export.) based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation, the share of recoverable thermal energy that gets utilized, and the share of useful thermal energy that is used for cooling compared to traditional heating.)

CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range

Table F-1
Technology Competition Assumed within Each Size Category

Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW RE
	70 kW MT
	150 kW PEMFC
500 - 1,000 kW	300 kW RE (multiple units)
	70 kW MT (multiple units)
	250 kW PEMFC (multiple units)
1 - 5 MW	3 MW RE
	3 MW GT
	2 MW MCFC
5 - 20 MW	5 MW RE
	10 MW GT
20 - 100 MW	40 MW GT
>100 MW Export	260 MW GT-CC

Within each of these size categories the payback for each technology is estimated using appropriate gas and electric rates for the utility region, size and load. .

The technology with the lowest payback is assumed to set the market acceptance share, which is a function of the percent of the market that will accept paybacks of different levels. The market acceptance share is based on this payback using the payback acceptance curve that determines what share of the market will accept a given payback.

The market acceptance share is applied to the technical market potential constrained by a maximum market penetration factor (from 32% to 64% depending on the size and scenario.) The resultant product equals the economic market for that region/size. The smaller the size bin, the greater the constraints on facilities considering CHP so the smallest size bins are multiplied by the smallest MMP factors and the largest sizes have corresponding fewer constraints so a larger share of the market is considered receptive to CHP.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The market penetration is allocated by competing CHP technology with a size/utility bin based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback.

As shown in **Table F-2**, some additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. All applications less than 5 MW were assumed to have an electric load factor of 80% (7,008 full load hours/year) and an 80% utilization of recoverable thermal energy. In the larger projects of 5 MW and larger, 90% electric load factor and 90% utilization of recoverable thermal energy are assumed.

Table F-2
Technology Competition Assumed within Each Size Category

Parameter	*Assumption*
Economic Life of CHP Technology	10 years – for technologies with < 1 MW power output
	15 years – for technologies with ≥ 1 MW power output
Amortization Discount Rate	10%
Electric Load Factor	80% – for applications with < 5 MW load
	90% – for applications with ≥ 5 MW load
Utilization of Recoverable Thermal Energy	80% – for applications with < 5 MW load
	90% – for applications with ≥ 5 MW load

G
APPENDIX: MARKET PENETRATION RESULTS BY SCENARIO

Table G-1
Cumulative Market Penetration 2005-2020 by Scenario

Scenario	Onsite CHP MW	Export CHP MW	Total Market Penetration MW	Description
Base Case	1,966	0	1,966	Expected future conditions with existing incentives
No Incentives	1,141	0	1,141	Remove SGIP, CHP incentive gas price, and CHP CRS exemptions)
Moderate Market Access	1,966	2,410	4,376	Facilitate wholesale generation export
Aggressive Market Access	2,479	2,869	5,348	$40/kW year T&D capacity payments for projects under 20 MW, global warming incentive, and wholesale export
Increased (Alternative) Incentives	2,942	0	2,942	Extended SGIP (incentives on first 5 MW for projects less than 20 MW, $0.01/kWh CHP production tax credit
Streamlining	2,489	0	2,489	Customer behavior changes: higher response to payback levels and greater share of market that will consider CHP
High R&D on Base Case	2,764	0	2,764	Rate of technology improvement accelerated 5 years
High Deployment Case	4,471	2,869	7,340	Accelerated technology improvement with aggressive market access and streamlining to improve customer attitudes and response

Table G-2
Base Case: 2010 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	23	51	44	11	24	153
	SMUD	1	3	3	1	0	8
	Other North	0	1	0	0	0	1
North Total		25	55	47	12	24	162
South	LADWP	0	0	0	0	5	6
	SCE	3	0	12	1	42	58
	SDG&E	0	0	2	0	6	8
	Other South	0	0	0	0	0	1
South Total		3	0	15	2	53	72
Grand Total		27	55	61	13	77	234

Table G-3
Base Case: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	96	161	177	35	44	512
	SMUD	5	10	11	3	0	29
	Other North	1	2	2	0	0	5
North Total		102	173	189	38	44	546
South	LADWP	4	5	9	2	10	29
	SCE	79	106	178	26	79	467
	SDG&E	14	23	35	3	11	85
	Other South	3	4	6	2	0	14
South Total		99	138	228	33	99	596
Grand Total		201	311	417	70	143	1,142

Table G-4
Base Case: 2020 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	167	239	286	72	74	839
	SMUD	8	14	18	5	0	45
	Other North	2	3	3	0	0	8
North Total		178	256	306	77	74	891
South	LADWP	7	5	14	5	15	47
	SCE	155	181	318	60	133	847
	SDG&E	28	39	63	6	18	155
	Other South	6	6	11	4	0	27
South Total		196	231	406	76	167	1,075
Grand Total		373	487	713	153	241	1,966

Table G-5
Base Case: Cumulative Penetration by Year and Technology

2010 Cumulative Market Penetration				
Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	21	4	0	3
500kW-1,000kW	55	0	0	0
1-5 MW	41	0	20	0
5-20 MW	8	0	6	0
>20 MW	0	0	77	0
All Sizes	124	4	103	3
2015 Cumulative Market Penetration				
Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	175	12	0	15
500kW-1,000kW	292	2	0	16
1-5 MW	370	0	45	3
5-20 MW	48	0	22	0
>20 MW	0	0	143	0
All Sizes	884	14	210	34
2020 Cumulative Market Penetration				
Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	332	23	0	19
500kW-1,000kW	457	10	0	20
1-5 MW	606	0	99	7
5-20 MW	104	0	48	0
>20 MW	0	0	241	0
All Sizes	1,499	33	388	46

Table G-6
Moderate Market Access: Export Market Cumulative Market Penetration 2010

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E				0	485	485
	SMUD				0	0	0
	Other North				0	0	0
North Total					0	485	485
South	LADWP				0	149	149
	SCE				0	215	215
	SDG&E				0	0	0
	Other South				0	25	25
South Total					0	389	389
Grand Total					0	874	874

Table G-7
Moderate Market Access: Export Market Cumulative Market Penetration 2015

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E				0	811	811
	SMUD				0	0	0
	Other North				0	0	0
North Total					0	811	811
South	LADWP				0	242	242
	SCE				0	351	351
	SDG&E				0	0	0
	Other South				0	43	43
South Total					0	636	636
Grand Total					0	1,448	1,448

Table G-8
Moderate Market Access: Export Market Cumulative Market Penetration 2020

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E				0	1,324	1,324
	SMUD				0	0	0
	Other North				0	0	0
North Total					0	1,324	1,324
South	LADWP				0	399	399
	SCE				0	613	613
	SDG&E				0	0	0
	Other South				0	74	74
South Total					0	1,086	1,086
Grand Total					0	2,410	2,410

Table G-9
Aggressive Market Access: 2010 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	28	58	61	21	26	194
	SMUD	1	4	5	2	0	12
	Other North	0	1	1	0	0	2
North Total		29	63	66	22	26	207
South	LADWP	0	0	1	2	6	9
	SCE	9	1	31	16	47	105
	SDG&E	1	0	6	2	6	15
	Other South	0	0	1	1	0	3
South Total		11	1	39	21	59	132
Grand Total		40	65	105	44	85	339

Table G-10
Aggressive Market Access: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	108	182	226	59	48	623
	SMUD	6	13	16	4	0	40
	Other North	1	2	2	0	0	5
North Total		116	198	244	63	48	668
South	LADWP	6	10	22	9	11	58
	SCE	96	126	233	59	87	601
	SDG&E	18	28	47	7	12	111
	Other South	3	4	8	4	0	20
South Total		123	168	310	79	110	790
Grand Total		239	366	554	141	158	1,458

Table G-11
Aggressive Market Access: 2020 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	190	274	362	109	80	1,015
	SMUD	11	19	25	7	0	62
	Other North	2	3	3	0	0	9
North Total		203	296	391	116	80	1,086
South	LADWP	11	14	38	16	18	97
	SCE	184	219	404	111	146	1,064
	SDG&E	35	48	82	13	20	198
	Other South	7	7	14	7	0	35
South Total		236	289	538	147	183	1,393
Grand Total		439	585	929	263	263	2,479

Table G-12
Aggressive Market Access: Cumulative Penetration by Year and Technology

2010 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	24	8	0	8
500kW-1,000kW	63	2	0	0
1-5 MW	57	0	47	1
5-20 MW	14	0	30	0
>20 MW	0	0	85	0
All Sizes	158	10	162	8

2015 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	198	19	0	22
500kW-1,000kW	339	5	0	22
1-5 MW	465	0	84	5
5-20 MW	81	0	61	0
>20 MW	0	0	158	0
All Sizes	1,082	24	302	49

2020 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	378	34	0	27
500kW-1,000kW	541	17	0	27
1-5 MW	759	0	159	11
5-20 MW	161	0	102	0
>20 MW	0	0	263	0
All Sizes	1,839	51	524	65

Table G-13
Aggressive Market Access: Export Market Cumulative Market Penetration 2010

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E				0	548	548
	SMUD				0	0	0
	Other North				0	0	0
North Total					0	548	548
South	LADWP				0	172	172
	SCE				0	244	244
	SDG&E				0	0	0
	Other South				0	28	28
South Total					0	444	444
Grand Total					0	992	992

Table G-14
Aggressive Market Access: Export Market Cumulative Market Penetration 2015

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E				0	940	940
	SMUD				0	0	0
	Other North				0	0	0
North Total					0	940	940
South	LADWP				0	290	290
	SCE				0	410	410
	SDG&E				2	0	2
	Other South				1	50	50
South Total					3	749	752
Grand Total					3	1,689	1,692

Table G-15
Aggressive Market Access: Export Market Cumulative Market Penetration 2020

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E				67	1,505	1,572
	SMUD				0	0	0
	Other North				0	0	0
North Total					67	1,505	1,572
South	LADWP				6	467	473
	SCE				35	700	735
	SDG&E				5	0	5
	Other South				1	83	84
South Total					47	1,249	1,297
Grand Total					115	2,755	2,869

Table G-16
Increased Incentives: 2010 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	28	59	96	32	31	245
	SMUD	1	4	7	2	0	15
	Other North	0	1	1	0	0	2
North Total		30	64	104	34	31	262
South	LADWP	0	0	1	6	8	16
	SCE	10	2	74	34	58	177
	SDG&E	1	0	15	4	8	28
	Other South	0	0	3	2	0	5
South Total		12	2	93	46	74	226
Grand Total		42	66	196	80	105	488

Table G-17
Increased Incentives: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	109	185	338	85	57	773
	SMUD	6	13	25	5	0	50
	Other North	1	2	3	0	0	6
North Total		117	200	366	90	57	830
South	LADWP	6	11	41	17	14	89
	SCE	97	128	363	95	106	789
	SDG&E	18	28	74	11	15	146
	Other South	4	4	12	6	0	26
South Total		125	172	490	129	135	1,050
Grand Total		241	372	856	219	192	1,880

Table G-18
Increased Incentives: 2020 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	191	278	478	138	94	1,177
	SMUD	11	19	35	8	0	73
	Other North	2	3	4	0	0	10
North Total		204	300	516	146	94	1,260
South	LADWP	11	16	59	25	23	134
	SCE	186	223	537	149	175	1,270
	SDG&E	35	49	109	18	24	236
	Other South	7	7	18	10	0	42
South Total		239	295	724	202	222	1,682
Grand Total		443	595	1,241	348	315	2,942

Table G-19
Increased Incentives: Cumulative Penetration by Year and Technology

2010 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	24	9	0	8
500kW-1,000kW	64	2	0	0
1-5 MW	87	0	105	4
5-20 MW	16	0	64	0
>20 MW	0	0	105	0
All Sizes	191	11	273	13

2015 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	197	22	0	22
500kW-1,000kW	344	6	0	23
1-5 MW	604	0	177	75
5-20 MW	96	0	122	0
>20 MW	0	0	192	0
All Sizes	1,241	27	491	120

2020 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	378	38	0	27
500kW-1,000kW	548	20	0	28
1-5 MW	898	0	261	81
5-20 MW	179	0	168	0
>20 MW	0	0	315	0
All Sizes	2,003	58	745	136

Table G-20
Streamlining: 2010 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	30	70	59	18	25	202
	SMUD	1	4	4	1	0	11
	Other North	0	1	1	0	0	2
North Total		32	76	63	20	25	215
South	LADWP	0	0	1	0	6	7
	SCE	5	0	17	2	45	69
	SDG&E	0	0	3	0	6	9
	Other South	0	0	1	0	0	1
South Total		6	0	22	2	57	86
Grand Total		37	76	85	22	82	301

Table G-21
Streamlining: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	131	223	216	52	48	670
	SMUD	7	13	15	3	0	37
	Other North	2	3	2	0	0	6
North Total		139	239	232	55	48	713
South	LADWP	5	8	17	5	10	46
	SCE	111	143	211	37	83	584
	SDG&E	20	30	41	4	11	107
	Other South	4	5	8	2	0	19
South Total		140	186	277	49	104	756
Grand Total		279	424	509	104	152	1,469

Table G-22
Streamlining: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	223	318	346	95	85	1,068
	SMUD	11	18	23	6	0	58
	Other North	3	4	3	0	0	10
North Total		237	340	372	101	85	1,136
South	LADWP	10	9	29	10	17	75
	SCE	212	236	375	80	149	1,052
	SDG&E	38	51	74	9	20	192
	Other South	8	8	13	5	0	34
South Total		268	303	492	105	186	1,353
Grand Total		505	643	864	206	271	2,489

Table G-23
Streamlining: Cumulative Penetration by Year and Technology

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	27	6	0	5
500kW-1,000kW	75	0	0	0
1-5 MW	55	0	29	0
5-20 MW	13	0	9	0
>20 MW	0	0	82	0
All Sizes	170	6	120	5

2015 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	241	17	0	21
500kW-1,000kW	399	3	0	22
1-5 MW	447	0	59	3
5-20 MW	72	0	32	0
>20 MW	0	0	152	0
All Sizes	1,158	20	244	47

2020 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	447	32	0	26
500kW-1,000kW	604	12	0	27
1-5 MW	732	0	124	8
5-20 MW	141	0	65	0
>20 MW	0	0	271	0
All Sizes	1,924	44	460	61

Table G-24
High R&D: 2010 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	35	53	66	17	26	196
	SMUD	2	4	5	1	0	12
	Other North	0	1	1	0	0	2
North Total		38	57	71	18	26	209
South	LADWP	2	3	7	3	6	21
	SCE	37	51	81	17	46	232
	SDG&E	7	11	16	2	6	42
	Other South	1	2	3	1	0	7
South Total		47	67	107	23	58	302
Grand Total		84	123	178	41	84	511

Table G-25
High R&D: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	149	251	232	54	49	735
	SMUD	9	18	16	4	0	47
	Other North	2	3	2	0	0	7
North Total		160	273	250	58	49	789
South	LADWP	10	21	25	7	11	73
	SCE	156	251	284	51	88	830
	SDG&E	30	55	57	5	12	159
	Other South	6	8	10	3	0	27
South Total		201	336	375	67	111	1,090
Grand Total		361	609	625	124	160	1,879

Table G-26
High R&D: 2020 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	230	334	348	93	80	1,085
	SMUD	13	23	23	6	0	64
	Other North	3	4	3	0	0	10
North Total		246	361	374	99	80	1,160
South	LADWP	14	22	31	10	17	94
	SCE	242	331	431	88	145	1,236
	SDG&E	46	73	86	10	20	234
	Other South	9	11	15	6	0	40
South Total		310	436	564	113	182	1,604
Grand Total		555	797	937	213	262	2,764

Table G-27
High R&D: Cumulative Market Penetration by Year and Technology

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	74	4	0	6
500kW-1,000kW	115	1	0	8
1-5 MW	163	0	14	1
5-20 MW	29	0	13	0
>20 MW	0	0	84	0
All Sizes	380	5	111	15

2015 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	181	14	0	167
500kW-1,000kW	175	5	0	429
1-5 MW	490	0	116	18
5-20 MW	84	0	40	0
>20 MW	0	0	160	0
All Sizes	930	18	316	614

2020 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	358	27	0	171
500kW-1,000kW	349	14	0	434
1-5 MW	740	0	174	23
5-20 MW	145	0	68	0
>20 MW	0	0	262	0
All Sizes	1,592	41	504	627

Table G-28
High Deployment Case: 2010 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	53	84	101	31	33	302
	SMUD	3	6	8	2	0	19
	Other North	1	1	1	0	0	3
North Total		57	91	109	33	33	323
South	LADWP	4	7	15	7	7	40
	SCE	56	82	131	35	60	364
	SDG&E	11	18	26	4	8	67
	Other South	2	3	5	2	0	11
South Total		73	110	176	49	75	482
Grand Total		130	201	286	82	108	806

Table G-29
High Deployment Case: 2015 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	237	426	369	85	64	1,182
	SMUD	15	31	26	6	0	78
	Other North	3	5	3	0	0	11
North Total		255	462	398	91	64	1,270
South	LADWP	19	46	50	17	13	146
	SCE	249	442	468	92	118	1,368
	SDG&E	48	99	94	11	16	268
	Other South	9	15	16	6	0	45
South Total		325	601	628	126	147	1,828
Grand Total		579	1,063	1,027	217	212	3,098

Table G-30
High Deployment Case: 2020 Cumulative Market Penetration

Region	Utility	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
North	PG&E	357	552	545	147	107	1,708
	SMUD	22	39	37	9	0	107
	Other North	5	6	5	0	0	16
North Total		383	597	587	156	107	1,831
South	LADWP	27	54	73	26	22	201
	SCE	377	561	703	151	197	1,989
	SDG&E	73	125	141	18	26	384
	Other South	14	18	24	10	0	66
South Total		490	759	941	206	245	2,640
Grand Total		873	1,355	1,528	362	352	4,471

Table G-31
High Deployment Case: Cumulative Market Penetration by Year and Technology

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	113	8	0	9
500kW-1,000kW	184	2	0	14
1-5 MW	256	0	26	3
5-20 MW	55	0	27	0
>20 MW	0	0	108	0
All Sizes	608	10	161	26

2015 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	281	24	0	274
500kW-1,000kW	285	10	0	768
1-5 MW	781	0	210	36
5-20 MW	143	0	74	0
>20 MW	0	0	212	0
All Sizes	1,491	34	495	1,078

2020 Cumulative Market Penetration

Size Range	Recip Engine	Microturbine	Gas Turbine	Fuel Cell
50-500 kW	547	46	0	281
500kW-1,000kW	551	28	0	776
1-5 MW	1,174	0	310	44
5-20 MW	239	0	123	0
>20 MW	0	0	352	0
All Sizes	2,511	74	785	1,100

H
POLICY OPTIONS LISTS AND DESCRIPTION

SGIP Modifications

A.“Unbundle” the SGIP Incentives

- Policy Description. The SGIP could focus on high value applications by decomposing the incentive into the following components: (1) minimum payment, (2) fuel conversion (= output Btu / input Btu), (3) location, (4) on-peak availability, and (5) dispatchability.
- Policy Objective. To promote CHP units with desirable attributes like high fuel conversion, good availability, flexible dispatchability, and correct location.
- Background/Context. The current simple per kW incentive defrays the high first-cost of a CHP unit, without reference to the unit’s attributes. But CHP units vary by fuel conversion, availability and dispatchability. A unit with high fuel conversion rate, on-peak availability and high dispatchability is more beneficial than without. All else constant, a CHP located in a resource-poor area is more cost-effective than one in a resource-rich area.
- Precedent. California’s Title-24 Standards are now time- and location- dependent, driven by the area-and-time specific avoided cost estimates. BCTC offers transmission credit to generation with desirable attributes.

B. Additional SGIP incentives for renewable CHP

- Policy Description. If a CHP uses renewable fuel, it should receive a renewable energy incentive.
- Policy Objective. To promote renewable CHP units.
- Background/Context. A CHP unit may burn renewable fuel (e.g., methane), instead of natural gas.
- Precedent. Even though most CHP units use natural gas as the main fuel, some may use renewable fuel (e.g., methane from landfill or biomass like wood waste). Since renewable CHP is more costly, it should receive a renewable energy incentive as well.

C. Fast processing of applications for the SGIP incentives

- Policy Description. Processing of applications for the SGIP incentives should be fast so that a CHP owner can receive its payment quickly with certainty.
- Policy Objective. To promote CHP adoption by expediting the review/approval/payment process.
- Background/Context. Delays in payment, whether expected or unanticipated by a CHP owner, can discourage adoption.

- Precedent. Simple and fast is the current practice by utilities in processing application for rebates for energy efficient appliance. A similar approach should be used for CHP. This may entail pre-qualifying CHP types and setting incentives by CHP attribute and installation location.

D. Assistance for preparing applications for the SGIP incentives

- Policy Description. There should be assistance to potential CHP users in understanding of and preparing applications for the SGIP incentives.
- Policy Objective. To help potential CHP users to learn about their CHP technology choice and the ensuing effect on the incentive amount.
- Background/Context. A complicated incentive scheme that encourages high value CHP installations can deter adoption, especially when a potential user does not know the effect of its choice of technology on the incentive amount.
- Precedent. The state tax credit was larger for passive (e.g., thermal mass for building cooling and heating) than active solar energy (e.g., collectors and pump for water heating). There was assistance from the Energy Commission to help builders and buyers to make the distinction between passive and active solar energy. Similar assistance should be available to a potential user to differentiate the various types of CHP.

Resource Adequacy

A. Count CHP – CCHP towards Resource Adequacy

- Policy Description. The value of CHP as a resource can be improved by including it towards the 15% planning reserve target.
- Policy Objective. To place CHP on the same level playing field in meeting the 15% target as resource options like renewable energy, price-induced demand response, and direct load control.
- Background/Context. The CPUC recently adopted the 15% planning reserve margin, requiring a load serving entity (LSE) to have capacity equal to 115% of its peak load. Absent this policy, the LSE will be less receptive to CHP programs.
- Precedent. California's history of Integrated resource planning treats demand- and supply-side resources equally.

B. No unwarranted de-rating of CHP's contribution to resource adequacy

- Policy Description. As a supply resource with known and metered output, CHP should not receive de-rating below actual performance.
- Policy Objective. To treat CHP the same way as other generation resources like hydro, geothermal or gas-fired units.
- Background/Context. DSM and wind energy are often de-rated to reflect their uncertain performance. Cost-effective CHP is likely due to consistent and stable demands for heat and power. Hence, its output is highly predictable and certain.
- Precedent. De-rating of a conventional resource like CT or CCGT is minimal, reflecting its low forced outage rate. The same should apply to CHP.

C. CHP's contribution to renewable energy portfolio standard (RPS)

- Policy Description. If a CHP uses renewable fuel, it should be counted towards meeting the 20% RPS.
- Policy Objective. To promote renewable CHP units.
- Background/Context. A CHP unit may burn methane or biomass, instead of natural gas.
- Precedent. Even though most CHP units use natural gas as the main fuel, some may use renewable fuel (e.g., methane from landfill or biomass like wood chips).

IOU Incentives

A. Financial Shareholder Incentives

- Policy Description. An IOU should have an incentive scheme that rewards its promotion of CHP. Besides recovery of program administration cost (see below), this scheme should reflect the MW of CHP installed and their attributes (e.g., fuel-efficiency, location, on-peak availability and dispatchability).
- Policy Objective. To provide profit opportunity such that IOU's profit maximization leads to CHP maximization.
- Background/Context. An important market barrier is the IOU's reluctance to promote CHP due to the lack of profit opportunity.
- Precedent. This is similar to PBR for DSM.

B. ERAM for CHP

- Policy Description. An IOU should receive rate adjustment to recover lost revenue due to CHP expansion.
- Policy Objective. To de-couple a utility's revenue from MWH sales so as to remove an IOU's incentive to block CHP implementation that reduces MWH sales.
- Background/Context. An important market barrier is the IOU's reluctance to promote CHP due to the fear of lost revenue, which can be very large under rapid CHP deployment.
- Precedent. This is similar to ERAM for DSM.

C. CHP Program Funding and Development

- Policy Description. An IOU should receive full cost recovery if asked to administer the CHP program.
- Policy Objective. To provide funding for program administration by an IOU.
- Background/Context. An important market barrier is the IOU's reluctance to promote CHP due to no program funding.
- Precedent. This is similar to DSM funding for administration cost.

D. IOU CHP Ownership

- Policy Description. An IOU should be able to own and operate CHP in partnership with the site owner (e.g., hotel).

- Policy Objective. To internalize barriers posted by an IOU to expand CHP and to improve the site owner's confidence in CHP's performance.
- Background/Context. An important market barrier is the IOU's reluctance to promote CHP due to conflict of interest. But if the IOU can own and operate CHP profitably, this reluctance vanishes. As well, a site owner may be more confident in CHP's performance if the utility is a willing partner.
- Precedent. This is similar to an IOU's affiliate owning and operating QF under power purchase agreements. However, this raises the unpleasant issue of self-dealing.

E. Market-based bill credit

- Policy Description. A CHP owner should be a full requirement customer of the utility and receive a bill credit based on the market price for the power produced by the CHP unit.
- Policy Objective. To remove the revenue loss fear of an IOU.
- Background/Context. So long as a CHP customer is a full requirement customer, the IOU does not suffer revenue loss. The bill credit is the CHP output at market by the utility. The CHP owner may love (hate) this arrangement if the market price expectation is higher (lower) than the tariff.
- Precedent. This is similar to SMUD's bill credit for retail access to wholesale market prices.

Rate Design Modifications

A. Net Metering for CHP – CCHP Applications

- Policy Description. A CHP owner should receive net billing based on its otherwise applicable tariff.
- Policy Objective. To remove the disincentive due to standby rate.
- Background/Context. A CHP owner bypasses the utility's service. Under complete bypass, the owner needs backup under the standby tariff that bills the owner's subscribed demand, resulting a fixed payment every month. If the owner can use its otherwise applicable tariff that bills metered consumption and demand, its monthly utility bill declines. In the case of partial bypass, net metering automatically lowers the owner's bill and obviates the need for standby service.
- Precedent. Net metering now applies to PV homes and DSM owners.

B. Discounted Net Metering for CHP – CCHP

- Policy Description. A CHP owner should receive discounted net billing based on its otherwise applicable tariff.
- Policy Objective. To remove the disincentive due to standby rate.
- Background/Context. A CHP owner bypasses the utility's service. Under complete bypass, the owner needs backup under the standby tariff that bills subscribed demand. If the owner can use a discounted version of its otherwise applicable tariff that bills metered consumption and demand, its monthly utility bill is likely small. In the case of partial bypass, net metering automatically lowers the owner's bill and obviates the need for standby service.
- Precedent. Net metering now applies to PV homes and DSM owners. Also, the 20/20 program rewards large energy savers.

C. Volumetric-based Tariff for CHP – CCHP Owners

- Policy Description. A CHP owner should receive net billing based on a new tariff with inverted block energy rates. The first block should be very cheap, but the last block very expensive.
- Policy Objective. To remove the disincentive due to the demand charges that may present in the otherwise applicable tariff.
- Background/Context. Demand charge can be very costly to a CHP owner when the unit is not available 100% of the time. If the new tariff only has inverted block rates, an owner uses few (many) kWh a month would pay little (big). This promotes reliable CHP units.
- Precedent. BCTC bills Clean Energy producers based on average load factor, not non-coincident demand. This helps reduce the producer's transmission bill.

D. Optional market-based bill credit

- Policy Description. A CHP owner should have the option to be a full requirement customer of the utility and receive a bill credit based on the market price for the power produced by the CHP unit.
- Policy Objective. To provide the CHP owner access to wholesale market without the complication of becoming a wholesale supplier.
- Background/Context. The CHP owner may love this arrangement if its market price expectation is higher than the tariff.
- Precedent. This is similar to SMUD's bill credit for retail access to wholesale market prices.

E. Eliminate Exit Fees for CHP – CCHP

- Policy Description. A CHP owner should not have to pay an exit fee for such items as the DWR contract costs and transmission fixed cost.
- Policy Objective. To remove the disincentive for bypassing the utility service using CHP.
- Background/Context. Exit fee makes CHP uneconomic for a potential owner, even if the CHP unit is socially cost-effective.
- Precedent. Exempting exit fee is similar to not asking a DSM owner to pay the per kWh (DWR contract) surcharge on kWh saved. The system throughput decline reduces a utility's revenue collection based on kWh charges. Hence, an ERAM mechanism is necessary to maintain the utility's financial viability.

F. "Rolled-in" Interconnection Costs for CHP

- Policy Description. A CHP owner should not have to pay for the gas/electric T&D investment triggered by its investment.
- Policy Objective. To remove the disincentive for bypassing the utility service using CHP.
- Background/Context. A new CHP may require the IOU to install new T&D facilities (e.g., inter-connection). If the entire T&D investment is imposed on the CHP owner, CHP can become uneconomic. Hence, the investment should be rolled into the class-specific revenue requirement.
- Precedent. Under FERC Order 888, a transmission provider can roll transmission investments into the rate base. This helps promote transmission expansion because a single transmission service requestor often cannot fund the project.

CHP Marketing and Branding

A. Education programs

- Policy Description. A local utility should work with the Energy Commission and other government agencies to provide education to potential CHP users chosen from the utility's billing files.
- Policy Objective. Not all electricity consumers understand CHP, making education critical for accelerating CHP adoption.
- Background/Context. This is similar to the education programs for other energy technologies. The programs may be low-cost and simple (e.g., bill inserts and web-based information) or high-cost and targeted (e.g., seminars for interested users; detailed analysis for those requested the information).

B. Qualified Provider List for Customers

- Policy Description. A local utility should work with vendors/installers and investors (e.g., GE capital and GE Energy) to develop a list of qualified suppliers of turn-key CHP packages.
- Policy Objective. CHP is not always well understood by its potential users. A preferred provider list achieves the twin goals of imparting trust and reducing transaction/information cost.
- Background/Context. This is similar to a list of qualified DSM and green energy suppliers.

C. Energy Commission Provider Certification

- Policy Description. A CHP user should easily find qualified suppliers, using a list developed/approved by the Energy Commission and the local utility.
- Policy Objective. To overcome the informational barrier that limit CHP market penetration.
- Background/Context. Few potential users know CHP suppliers well. Lack of seller knowledge translates into inertia driven by risk-aversion, albeit extensive financial incentives available.
- Precedent. This similar to the Energy Efficiency labeling program. It is also similar to references provided by large stores like Home Depot.

D. Low Cost Financing

- Policy Description. A local utility should work with the state and private firms to develop low-cost financing for CHP.
- Policy Objective. Low cost financing is important to overcome the first-cost barrier.
- Background/Context. A potential buyer like a school district may not have the up-front money to pay for the unit. Financing can come from the district's bond sale (if possible), third party investors like GE Capital, the utility, or a government agency that offers tax-free bonds. A loan guarantee by the utility or a government agency can also greatly reduce cost of financing.
- Precedent. Government-aided financing for worthy activities is common (e.g., Fannie Mae for home ownership, Sallie Mae for student loans, SBA for business loans).

E. Free CHP Assessment and Audit

- Policy Description. A CHP owner should not have to pay for the cost of a CHP study performed by an IOU.
- Policy Objective. To encourage potential users to explore CHP.
- Background/Context. A potential user like a school district may not have the money to fund a study. Using CHP vendors who provide free consultation is unwise due to the vendors' sale motive.
- Precedent. California utilities provide energy efficiency and DSM audits at no cost.

F. Targeted marketing

- Policy Description. With the help of a local utility, CHP marketing should be directed to the right customers.
- Policy Objective. To remove the barrier due to divergence in interests between the bean counter and the engineer.
- Background/Context. The bean counter's objective is cost minimization, likely inconsistent with the O&M engineer's objective of reliable supply of energy services. While the bean counter wants lower cost, the engineer wants the status quo of reliable and safe operation. Hence both parties must be included in the CHP marketing effort.
- Precedent. This is similar to the problem commonly encountered in energy efficiency (or retail direct access) marketing.

G. Information protocol

- Policy Description. A CHP owner should be able to request its own electricity consumption data from the utility for use by CHP vendors.
- Policy Objective. To supply necessary information by a potential users to CHP vendors when issuing a RFP.
- Background/Context. A potential user may issue a RFP to choose a CHP vendor. But CHP vendors need detailed data to formulate their bids.
- Precedent. This is similar to the information protocol for direct retail access in California.

State Tax Incentives

A. Tax credit for CHP owners

- Policy Description. CHP should receive tax credit, whose design should ideally reflect a CHP unit's desirable attributes, like the SGIP incentive. If the owner (e.g., non-profit school) does not pay tax, it should be able to let the vendor or the financing party to take the credit under a pre-approved lease/transfer agreement.
- Policy Objective. To accelerate CHP adoption.
- Background/Context. Tax credit is a common tool to accelerate adoption of a preferred technology because it reduces the owner's tax liability.
- Precedent. Solar tax credit in the 1970s, PV credit now, and hybrid car credit now. Existing Oregon tax credit.

B. Tax credit for CHP suppliers

- Policy Description. CHP suppliers should receive tax credit for R&D and CHP sales. The sales-based credit should ideally reflect a CHP unit's desirable attributes, like the SGIP incentive.
- Policy Objective. To accelerate CHP development and adoption.
- Background/Context. Tax credit is a common tool to accelerate the development of a preferred technology because it reduces the supplier's tax liability.
- Precedent. Tax credits are routinely given to specific investments, spending on R&D activities, cost of employing handicapped workers.

Portfolio Standards

A. Statewide CHP Portfolio Standards

- Policy Description. The state should adopt a CHP target as a percent of total energy consumed in the state.
- Policy Objective. To ensure actions are taken by the utilities to achieve the target.
- Background/Context. Absent a hard target, not much will happen. Without the fuel efficiency standard, the auto industry would have been reluctant to achieve the current gas mileage. This point is best supported by the fact that the auto industry is fighting against, rather than happily endorsing, any tightening of the standard.
- Precedent. California and other states have renewable energy portfolio standard.

Other Actions

A. Fast and easy permitting

- Policy Description. A CHP owner should have easy permitting.
- Policy Objective. To reduce the potentially high permitting cost due to CHP.
- Background/Context. Government agencies may not quickly issue permits required for CHP installation because of emission concerns and safety issues.
- Precedent. The Energy Commission has expedited process for peaking plants.

B. Subsidized training for CHP technicians

- Policy Description. The Energy Commission should work with the utilities and vendors to develop a subsidized training program for CHP technicians.
- Policy Objective. To ensure there will be enough technicians to service CHP units.
- Background/Context. If a potential user worries about getting maintenance and repair service, it may not adopt CHP.
- Precedent. Training programs are common for new technologies.

C. Development of the CHP industry's infrastructure

- Policy Description. The Energy Commission should work with financial companies, utilities and vendors to develop an infra-structure for the CHP industry.

- Policy Objective. To ensure that a potential user can easily search for CHP information, find qualified vendors, obtain financing, receive quick permitting, buy input supply, hire maintenance/repair service, … etc.
- Background/Context. A successful technology (e.g., energy-efficient lighting, PC or Internet) must have a good infra-structure that can support a user's adoption, installation, financing, and operation.
- Precedent. Private sector can provide the infra-structure for some technologies (e.g., efficient AC) that are commonly used and have large customer base. But if the potential customer base is small (e.g., solar energy and electric cars), government intervention may be necessary.

D. Overcoming landlord / tenant barrier

- Policy Description. Whether the potential user is a landlord or a tenant should not deter CHP adoption.
- Policy Objective. To remove the adoption barrier due to the divergence of interests between the landlord and tenant.
- Background/Context. If a landlord charges its tenant for power and heat, it has little incentive to adopt CHP. But if a landlord charges an all-inclusive rent ($/sq.ft.), it has the incentive to install CHP to reduce its cost of operation. A tenant has little incentive to install CHP if it does not need to pay power and heat. Even if it has to pay power and heat, it does not want to spend money on a long-living CHP due to a short lease or uncertain tenure.
- Precedent. This is the same problem faced by energy efficiency technologies.

F. Subsidized fuels

- Policy Description. Besides gas sold by a utility, CHP owners should have subsidized fuels (e.g., butane, propane).
- Policy Objective. To extend CHP to areas without gas supplies.
- Background/Context. CHP may burn butane or propane. But the fuel cost may be too high. If CHP can have lower natural gas rates, it should also have subsidized fuels.
- Precedent. Electric / hydrogen cars receive subsidized fuels.

Research and Development Funding for CHP

A. R&D funding for CHP

- Policy Description. The Energy Commission should provide R&D fund for CHP to research institutes and universities.
- Policy Objective. To ensure enough funding to improve CHP technologies.
- Background/Context. Lack of an immediate large profitable market deters funding by the private sector.
- Precedent. R&D funding for technologies is a common government action.

I
BENEFIT COST ANALYSIS INPUT ASSUMPTIONS

The input assumptions used in the E3 benefit-cost analysis of policy options are provided in this Appendix. The technology cost and operating assumptions are the same as those provided in Appendix E: (Technology Cost and Performance Assumptions) and are not included again in this Appendix.

Customer Financing Assumptions

Customer Financing		
	Customer	
Borrowing rate		8%
Equity hurdle rate		20%
Leverage (debt/total financing)		75%
Tax rate		45%
After-tax WACC		8.300%
Term of financing		10
Customer Carrying Charge (%)		15.1%

Customer Waste Heat Application (Base Case)

Waste Heat		
	Base Case	
Waste Heat Application? (yes/no)	yes	
Percent of Energy Recovery		5,593
Efficiency of Replaced Use (e.g. boiler)		80%
Recovered Fuel (Btu/kWh)		6,991
Value of Displaced Fuel $/MMBtu	$	6.66
Value per kWh of DER Generation		0.047

Customer Back-up Reliability Value (only used in High Value Sensitivity Case)

Backup Reliability		
	High Case	
Backup power Application? (yes/no)		yes
Value per Year of Backup ($)	$	50,000
Size of Required DG system (kW)		500
Value per kW of DG system ($/kW)	$	100.00

SGIP Value for Customer

SGIP Incentive		
Technology Size (kW)	300	
Technology Type (1, 2, or 3)	3	
	Base Case	**Increased Case**
Gross Incentive $/kW - Nat. Gas CHP	$600	$800
Maximum Size	5,000	20,000
Maximum Incentive Size	1,000	5,000

Utility: T&D Capacity

T&D Capacity				
Inputs	Base Case		Deferral Value Assumptions	
T&D Constrained Area? (yes/no)	no		Inflation	2%
Deferrable Investment ($000s)	2000		WACC	6%
Required DG Capacity (MW)	1			
Utility Value $/kW-year	$ -			

Utility: Economic and Losses Assumptions

Economic and Losses Assumptions	
Inputs	**Base Case**
Utility After-tax WACC	8%
Estimated useful life of device	15
Utility Carrying Charge	12%
Average Marginal Energy Losses	7%
Marginal Peak Losses for Gen Capacity	11%
Marginal Peak Losses for T&D	10%

Utility: Rate Structure (SCE example)

Rate Structure	
Inputs	**Base Case**
Total Average Rate $/kWh	$ 0.14
Avg. Class Load Factor	40%
Energy Rate $/kWh	$ 0.0837
Demand Charge $/kW-mo	$ 17.87
Reservation Demand Charge Default	$ -

Wholesale Energy and Fuel Cost Assumptions

		Wholesale Energy	Fuel Costs 2005 $/MMBtu						
		Market Price		North			South		
			EG Case	Cogen / EG	Com	Ind	Cogen / EG	Com	Ind
2005	Level (chp owner)	$0.065	$6.512	$6.062	$6.812	$6.212	$6.512	$7.262	$6.662
	Level (utility)	$0.066	$6.607	$6.157	$6.907	$6.307	$6.607	$7.357	$6.757
	Level (society) *	$0.066	$6.636	$5.936	$5.936	$5.936	$5.936	$5.936	$5.936
2010	Level (chp owner)	$0.067	$6.724	$6.274	$7.024	$6.424	$6.724	$7.474	$6.874
	Level (utility)	$0.068	$6.846	$6.396	$7.146	$6.546	$6.846	$7.596	$6.996
	Level (society) *	$0.068	$6.908	$6.208	$6.208	$6.208	$6.208	$6.208	$6.208
2015	Level (chp owner)	$0.070	$7.085	$6.635	$7.385	$6.785	$7.085	$7.835	$7.235
	Level (utility)	$0.071	$7.206	$6.756	$7.506	$6.906	$7.206	$7.956	$7.356
	Level (society) *	$0.071	$7.264	$6.814	$6.814	$6.814	$7.264	$7.264	$7.264
	2005	$ 0.067	7.19	6.74	7.49	6.89	7.19	7.94	7.34
	2006	$ 0.068	6.72	6.27	7.02	6.42	6.72	7.47	6.87
	2007	$ 0.066	6.20	5.75	6.5	5.9	6.2	6.95	6.35
	2008	$ 0.059	5.76	5.31	6.06	5.46	5.76	6.51	5.91
	2009	$ 0.063	6.26	5.81	6.56	5.96	6.26	7.01	6.41
	2010	$ 0.064	6.39	5.94	6.69	6.09	6.39	7.14	6.54
	2011	$ 0.065	6.49	6.04	6.79	6.19	6.49	7.24	6.64
	2012	$ 0.066	6.59	6.14	6.89	6.29	6.59	7.34	6.74
	2013	$ 0.067	6.69	6.24	6.99	6.39	6.69	7.44	6.84
	2014	$ 0.067	6.77	6.32	7.07	6.47	6.77	7.52	6.92
	2015	$ 0.068	6.84	6.39	7.14	6.54	6.84	7.59	6.99
	2016	$ 0.068	6.90	6.45	7.2	6.6	6.9	7.65	7.05
	2017	$ 0.069	6.97	6.52	7.27	6.67	6.97	7.72	7.12
	2018	$ 0.069	7.02	6.57	7.32	6.72	7.02	7.77	7.17
	2019	$ 0.070	7.08	6.63	7.38	6.78	7.08	7.83	7.23
	2020	$ 0.070	7.13	6.68	7.43	6.83	7.13	7.88	7.28
	2021	$ 0.071	7.23	6.78	7.53	6.93	7.23	7.98	7.38
	2022	$ 0.071	7.30	6.85	7.60	7.00	7.30	8.05	7.45
	2023	$ 0.072	7.37	6.92	7.67	7.07	7.37	8.12	7.52
	2024	$ 0.072	7.44	6.99	7.74	7.14	7.44	8.19	7.59
	2025	$ 0.073	7.51	7.06	7.81	7.21	7.51	8.26	7.66
	2026	$ 0.074	7.58	7.13	7.88	7.28	7.58	8.33	7.73
	2027	$ 0.074	7.65	7.20	7.95	7.35	7.65	8.40	7.80
	2028	$ 0.075	7.72	7.27	8.02	7.42	7.72	8.47	7.87
	2029	$ 0.075	7.79	7.34	8.09	7.49	7.79	8.54	7.94
	2030	$ 0.076	7.86	7.41	8.16	7.56	7.86	8.61	8.01
	2031	$ 0.076	7.93	7.48	8.23	7.63	7.93	8.68	8.08
	2032	$ 0.077	8.00	7.55	8.30	7.70	8.00	8.75	8.15
	2033	$ 0.077	8.07	7.62	8.37	7.77	8.07	8.82	8.22
	2034	$ 0.078	8.14	7.69	8.44	7.84	8.14	8.89	8.29
	2035	$ 0.078	8.21	7.76	8.51	7.91	8.21	8.96	8.36
	2036	$ 0.079	8.28	7.83	8.58	7.98	8.28	9.03	8.43
	2037	$ 0.080	8.35	7.90	8.65	8.05	8.35	9.10	8.50
	2038	$ 0.080	8.42	7.97	8.72	8.12	8.42	9.17	8.57
	2039	$ 0.081	8.49	8.04	8.79	8.19	8.49	9.24	8.64

J
INTERVIEW GUIDE

CHP/CCHP Market Assessment

Interview Guide

Respondent Information

Name:

Title:

Company:

Telephone Number:

Interviewer:

Interview Date:

Interview Time:

Interview/sequence number (e.g., SM01, BB03):

I. Introduction

Hello, this is __________ and I work with Primen. We had an interview scheduled for this time. Is this still a good time for you? (If so, continue. If not, re-schedule for a more convenient time).

Just to remind you what we'll be talking about today: we are working with the California Energy Commission to get your opinion on policy initiatives that would encourage CHP applications in California.

A. Confidentiality

All information you provide will be kept confidential, and under no circumstances will any salesperson call you as a result of your participation in this study.

B. Taping

With your permission, I would like to record this interview to avoid slowing down our conversation in order to take written notes. We will not use the tapes for anything other than note taking and analysis.

II. Background Information

A. Please describe your facility (including size in sq. ft.) and the primary processes/operations that occur there.

a. Which of these processes consume the most energy?

B. What are your responsibilities with respect to facility and energy management?

C. What is the approximate total electrical demand of the facility (kW or MW)? ***Capture both average demand and peak demand if known.***

D. Approximately how much natural gas do you consume at this facility? What are the primary processes that use natural gas?

E. Do any of your processes produce waste gasses that could be combusted? If so, how much gas is produced and how is it currently dealt with? What would be involved in capturing these gasses for on-site generation?

III. Prior and Current On-Site Generation Projects

A. Do you currently generate all or part of your power on a regular basis? ***If no, skip to IV***

B. What types and sizes of generators do you use for this purpose? ***(Capture approximate size/output, fuel, dual-fuel capabilities, and distinctions between engines/turbines/more "exotic" technologies. Make sure they are describing base load generation applications, not standby or peak shaving units.)***

C. Approximately what % of your total electrical needs do you generate at this facility?

D. Do the generators produce heat that could be/is captured and used for other purposes? If useable waste heat is available but not being tapped, why not? What would be involved in capturing and using the heat?

E. Do the generators produce steam and/or chilled water through cogeneration?

IV. Decision-making process for recently completed or considered on-site generation projects

[Interviewer note – adapt the questions in this section as appropriate depending on whether you are discussing a recently completed project or a project they are currently (or have recently) considered.]

A. What prompted you to first consider this on-site generation project?

B. What were the primary drivers for this project (savings on electricity/energy costs, power reliability, power quality, stabilizing energy costs, other)?

C. Did you plan to . . .

1. Design the system in-house?
2. Purchase/own the generators or lease them?
3. Finance the project using your own capital resources, your company's usual lenders, or finance it through the project developer?

D. Who within your organization championed the project? Why?

E. Who were the other important stakeholders who had to be convinced? What ultimately appealed to them about the project?

F. What concerns did people raise about the project? How were they addressed? Which one was the hardest to address? Why?

G. How much of an impact did each of the following have on your ability to go forward with the project***? (Vary the order in which you ask about each factor. Probe for as much detail as possible on each, especially if they say it had a big impact. If they say one or more of the following was a non-issue, find out why.)***

1. Your company's financial position and/or the state of the economy at the time of the project
2. Electricity prices
3. Natural gas prices
4. Uncertainty about future energy prices and energy policies
5. The availability of specific state incentives/rebates
6. Other state regulatory issues **(describe)**
7. The availability (or lack thereof) of financing from the vendor/project developer
8. Specific warranties/guarantees provided
9. The nature of the service agreement included/offered
10. Support from the vendor/project developer in addressing environmental or permitting issues
11. Your electric utility's attitude toward the project
12. The ability to cogenerate heat, steam, or chilled water
13. Other specific features of the generation technology
14. Other issues? (**describe**)

B. Which of these issues had the greatest impact? **(Use this response to probe during the policy section**)

C. If "utility attitude" was cited as an issue, probe for details.

V. Future Prospects for CHP/CCHP

A. How likely is it that you will install additional on-site generation within the next two years for CHP/CCHP? ***(Try for a probability/percent likelihood rating)***

B. ***For any DE projects they say are likely or being considered:***

i. How large would this project likely be (kW)?

ii. What would the primary drivers for this project be (savings on electricity/energy costs, power reliability, power quality, stabilizing energy costs, other)?

iii. What concerns are people likely to raise about the project? How will they be addressed? Which do you expect to be the hardest to address? Why?

iv. How much of an impact is each of the following likely to have on your ability to go forward with the project? ***(Vary the order in which you ask about each factor. Probe for as much detail as possible on each, especially if they say it will have a big impact. If they say one or more of the following is a non-issue, find out why.)***

1. Your company's financial position and/or the state of the economy at the time of the project
2. Electricity prices
3. Natural gas prices
4. Uncertainty about future energy prices and energy policies
5. The availability of specific state incentives/rebates
6. Other state regulatory issues **(describe)**
7. The availability (or lack thereof) of financing from the vendor/project developer
8. Specific warranties/guarantees provided
9. The nature of the service agreement included/offered
10. Support from the vendor/project developer in addressing environmental or permitting issues
11. Your electric utility's attitude toward the project
12. The ability to cogenerate heat, steam, or chilled water
13. Other specific features of the generation technology
14. Other issues? (**describe**)

C. Which of these issues had the greatest impact? (**Use this response to probe during the policy section**)

D. If "utility attitude" was cited as an issue, probe for details.

E. Are there other on-site generation projects that have been discussed but that are not likely to proceed at present? What would have to change for them to proceed? ***(Economy improve, gas prices drop/stabilize, other??)***

VI. Policy Initiatives

Now I want to talk with you about some issues that you may have faced at different points in the CHP project development, and some ideas being considered as policy changes to address these issues.

A. Project planning assistance

a. During the project planning phase, is/was finding a vendor an issue for you?

i. If so, would a qualified vendor list from your local utility be helpful to you? Why or why not?

ii. Would a vendor certification list from the California Energy Commission be helpful? Why or why not?

b. Is/was obtaining financing an issue for you?

i. If so, would the availability of CA state financing make a difference? Why or why not?

ii. Would the availability of low cost financing make a difference?

1. If so, what rates would you need in order to make the project go forward? (**probe for what rate they think they could get now and what they would consider "low-rate**")

c. Is/was permitting an issue for you?

i. If so, would a faster permitting process make a difference? Why or why not?

ii. Would a less complicated, more streamlined permit process make a difference? Why or why not?

B. Subsidies to address capital costs

a. Are you familiar with SGIP – the Self Generation Incentive Program?

i. **If they are familiar with SGIP**, did you apply for funding for your project?

1. How did that process go?

2. Did the program make a difference in the project going forward or not?

3. Is there anything that you would change about the program or the process of applying?

a. Would assistance in preparing the SGIP application make a difference in whether the project went forward?

b. Would faster processing of SGIP applications make a difference?

If not, define: The Self Generation Incentive Program, or SGIP, provides financial incentives to customers who install on-site distributed generation. The incentive is to help offset installed capital costs. The incentive is available for projects up to 5 MW, but the subsidy only applies to 1MW of generating capacity.

ii. Assume the eligibility requirement was increased to include projects of up to 20 MW, but still only applied to the first 1 MW of generating capacity. Would this change help in getting your project to go forward? Why or why not?

iii. Now assume that the eligibility requirement was increased to include projects of up to 20 MW AND the incentive is increased from 1 MW.

1. Would this change help in getting your project to go forward? Why or why not?

2. How much would the incentive have to increase from the current 1 MW in order for it to make a difference in your project going forward?

C. Ways of improving overall project economics

In addition to direct subsidies to offset capital costs, there are several other policy changes that could potentially improve the overall economics of CHP projects. I'd like to get your reaction to several such options. **[Vary the order in which you go through this list for different respondents. Assess respondent's interest in each one. For those that strike a chord, probe for details (how much of a difference it would likely make in completing a project, how big the incentive would have to be, etc.).]**

a. A state tax credit for CHP owners

b. Net metering, which would allow you to sell excess power back to the grid

c. A credit on your monthly electric bill that equaled the wholesale price of the power you produced on-site

d. The option for CHP owners to switch to a non-demand electric rate

e. The elimination of exit fees for CHP owners

f. The elimination of interconnection costs for CHP projects

g. The option for CHP owners to purchase natural gas at a lower rate than they currently can

h. The option for CHP owners to purchase natural gas on a forward price basis, to avoid fuel price volatility

D. Are there any other initiatives that you think would be effective in encouraging CHP in California? If so, what are they?

E. If the state could only do one of these policy changes, which would be the most useful to you in getting your CHP project completed? **[Make sure they understand that you are talking about any of the options discussed, not just those in C.]**

VII. Wrap-up

A. Is there anything else related to this topic that we haven't already discussed that you would like to mention?

B. If I have clarification questions as I am reviewing my notes, may I call you back for clarification?

C. Verify respondent's email address for copy of final report.

Email: